Duvernay Reserves and Resources Report

A Comprehensive Analysis Of Alberta's Foremost Liquids-Rich Shale Resource

December 2016

Principle authors: Adam Preston, Graeme Garner, Krista Beavis, Omair Sadiq, Sean Stricker

Contributors: Jim Jenkins, Kevin Parks, Shauna Miller, Michael Teare, Fran Hein, Courtney Whibbs, Yangchen Sheka

Internal Technical Reviewers: Hilary Corlett, Dean Rokosh

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Website: www.aer.ca

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Executive Summary

The Alberta Energy Regulator (AER) ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources over their entire life cycle. As part of this mandate, one of the AER's key services is to provide credible information about Alberta's energy reserves and resources. The AER has moved to a more flexible play-based approach with more probabilistic methods to help capture the uncertainty of unconventional reserves and resources.

This report is an unbiased and independent assessment of the Duvernay Formation resource endowment and strives to present the Duvernay's reserves in a credible, accurate, transparent, and audible way. Additional reserves and resource reports will be released for key formations as soon as analysis is completed.

Due to the nature of unconventional reserves and resources, increasing the knowledge of both the geology and engineering aspects of the Duvernay Formation will help stakeholders manage the risks of development.

The Duvernay Formation is the source rock for historical conventional hydrocarbon production, and it is now emerging as Alberta's foremost unconventional shale resource. Since 2011, the Duvernay has been developed through the use of horizontal multistage fracturing technology. Despite the low commodity price environment, activity in the condensate-rich areas of the Duvernay remains steady. Condensate is a key product used to dilute bitumen, allowing for flow to market. Due to its close proximity to the Canadian oil sands, the liquids-rich areas of the Duvernay are well positioned for growth. The condensate and liquids also have high value as feedstocks for Alberta's petrochemical industry.

As operators continue to pilot well spacing and completion strategies within the liquids-rich areas of the resource, additional drilling and completion efficiencies may be achieved. This will allow operators to enhance completions design and pad development within the optimal geological areas to unlock the liquids potential held by this resource.

The developed portions of the Duvernay geological plays have been subdivided into assessment areas for the 2016 assessment: Kaybob in the north, Edson-Willesden Green in the central and Innisfail in the south. These assessment areas were determined based on similar geological characteristics and current development trends.

The following table summarizes the initial and remaining reserves estimated for oil, gas, and condensate across the Duvernay, effective January 1, 2016.[1] The total remaining proved reserves are 354 MMboe and proved plus probable reserves are 395 MMboe.

1 When deciding between the accuracy of numbers and the readability of this report, it was determined that reporting numbers to the last available digit was not reasonable and that the effect on the overall values would be negligible. As such, in some instances, the reserves numbers by assessment area may not add up exactly to the numbers displayed in the regional reserves table.

Of the remaining 395 MMboe total proved plus probable reserves, approximately 96% are located within the Kaybob assessment area. Based on these estimates, the condensate-rich areas of the Kaybob assessment area are poised for increased growth within the next five years.

Contingent resources in the Duvernay have been classified as "development unclarified". Low estimate unrisked contingent resources are 1540 MMboe and best estimate unrisked contingent resources are 1676 MMboe.

Prospective resources in the Duvernay have been subclassified by maturity status, "prospect." A commercial risk factor of 50% was applied to derive a risked estimate. Risked best estimate prospective resources are 864 MMboe.

The AER welcomes questions and feedback on the content of this report. Feedback can be emailed to Reserves@aer.ca.

Total Duvernay reserves effective January 1, 2016

	Initial				Remaining			
	Oil (MMbbl)	Gas (Bcf)	Condensate (MMbbl)	BOE (MMboe)	Oil (MMbbl)	Gas (Bcf)	Condensate (MMbbl)	BOE (MMboe)
Proved								
Developed Producing	6	393	30	101	5	315	24	81
Developed Nonproducing	0	4	0	1	0	0	0	0
Undeveloped	29	737	121	273	29	737	121	273
Total	**35**	**1134**	**151**	**375**	**34**	**1052**	**145**	**354**
Proved + Probable								
Developed Producing	6	453	35	117	6	375	28	96
Developed Nonproducing	0	4	0	1	0	0	0	0
Undeveloped	32	783	136	299	32	783	136	299
Total	**38**	**1240**	**171**	**417**	**38**	**1158**	**164**	**395**

MMbbl – million barrels

Bcf – billion standard cubic feet

MMboe – million barrels of oil equivalent

1 Introduction

This report is an unbiased and independent assessment of the Duvernay Formation resource endowment and strives to present the Duvernay's reserves in a credible, accurate, transparent, and audible way in support of the *Oil and Gas Conservation Act*, Part 1. This will set an international standard for methods of reserves and resources reporting through the adoption of aspects of the Canadian Oil and Gas Evaluation Handbook (COGEH; SPEE, 2007) and the Society of Petroleum Evaluation Engineers (SPEE) *Monograph 3: Guidelines for the Practical Evaluation of Undeveloped Reserves in Resource Plays* (SPEE, 2010).

Due to the nature of unconventional reserves and resources, increasing the knowledge of both the geology and engineering aspects of the Duvernay Formation will help all stakeholders manage the risks of development. The assessment can be used when making decisions regarding future resource activity and guide regulation and policy development over broad regions and long periods of time.

1.1 Definitions and Methodology

The terms "resource" and "reserve" are often used interchangeably but have different meanings in reporting frameworks. A resource is generally accepted to be all those quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, including all known and estimated quantities yet to be discovered. A reserve, on the other hand, is an estimate of remaining quantities of petroleum anticipated to be economically recoverable from known accumulations as of a given date, given established technology. Full and half-cycle economics of the Duvernay have not been considered; broad qualitative methods were used to assess the economic viability of the resource.

Petroleum reserves and resources estimates are used for many different purposes, including inventory and supply forecasting, corporate and capital planning, and securities-related reporting. In these cases, evaluations are done for investment, securities, financing, and insurance purposes and must adhere to strict rules related to commerciality and certainty over a prescribed time interval to protect consumers and maintain confidence in markets. This report should not be confused with annual, securities-related reserves reporting completed by corporate entities involved in resource extraction for profit.

Despite the different purposes and users of reserves and resources information, some overlap does exist between corporate business processes, resource management functions, and energy and mineral studies. In an effort to promote consistency and to better accommodate this overlap, the AER has adopted aspects of the Canadian Oil and Gas Evaluation Handbook (SPEE, 2007) to communicate with clarity to external stakeholders using common terminology.

The life cycle of development of a play should optimize economics and conserve resources, despite incomplete knowledge of the subsurface and technical challenges in remote environments. A life cycle includes exploration, testing, piloting, development and abandonment and closure. The Duvernay is considered to be in the testing phase.

Probabilistic techniques were used to analyze data and generate the results provided in this report. Estimates are summarized by a P50 value, which is considered to be the best estimate because it minimizes the expected variance from the unknown, true value. The range of uncertainty is summarized by the P90 (low estimate) and P10 (high estimate) values.

A barrels of oil equivalent (BOE) conversion ratio of 6 thousand cubic feet (Mcf): 1 barrel (bbl) has been used in this report. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. The BOE conversion was used primarily for illustrative purposes and so that the reserves estimates released in this report are comparable to external industry estimates.

When deciding between the accuracy of numbers and the readability of this report, it was determined that reporting numbers to the last available digit was not reasonable and that the effect on the overall values would be negligible. As such, in some instances, the reserves numbers by assessment area may not add up exactly to the numbers displayed in the total reserves table.

1.2 Duvernay Formation Summary

The Duvernay Formation covers an area of approximately 130 000 square kilometres, or 20% of the area of Alberta (Figure 1).

The AER and Alberta Geological Survey have published resource estimates for formations in Alberta (Rokosh et al., 2012). In summary, the total in-place resource endowment for the Duvernay ranges from 350 to 540 trillion cubic feet of natural gas, 7 to 16 billion bbl of natural gas liquids, and 44 to 81 billion bbl of oil. These estimates support that the Duvernay shale contains a massive initial resource in place; however, the amount of this resource that can be economically recovered is dependent on drilling and completions optimization, cost reductions, expected liquids yields, commodity pricing, and social, environmental, and regulatory constraints. Despite the uncertainty associated with these technical, social, and economic factors, operators working in the Duvernay continue to drill new wells within the liquids-rich regions of the resource. This demonstrates that as the understanding of this complex resource continues to improve, and new breakthroughs in technology are discovered, further costs savings are being realized. As development continues, operators can delineate optimal geological areas and unlock the liquids potential contained in this resource.

Development growth within the core acreage of this formation continues despite the current low commodity price environment, bolstering the Duvernay's status as a world-class shale resource.

1.3 Scope of Work

The AER has subdivided the extent of the Duvernay depositional area into two geological plays: Duvernay Fox Creek is the larger play in the northwest and exists in the Devonian West Shale Basin,

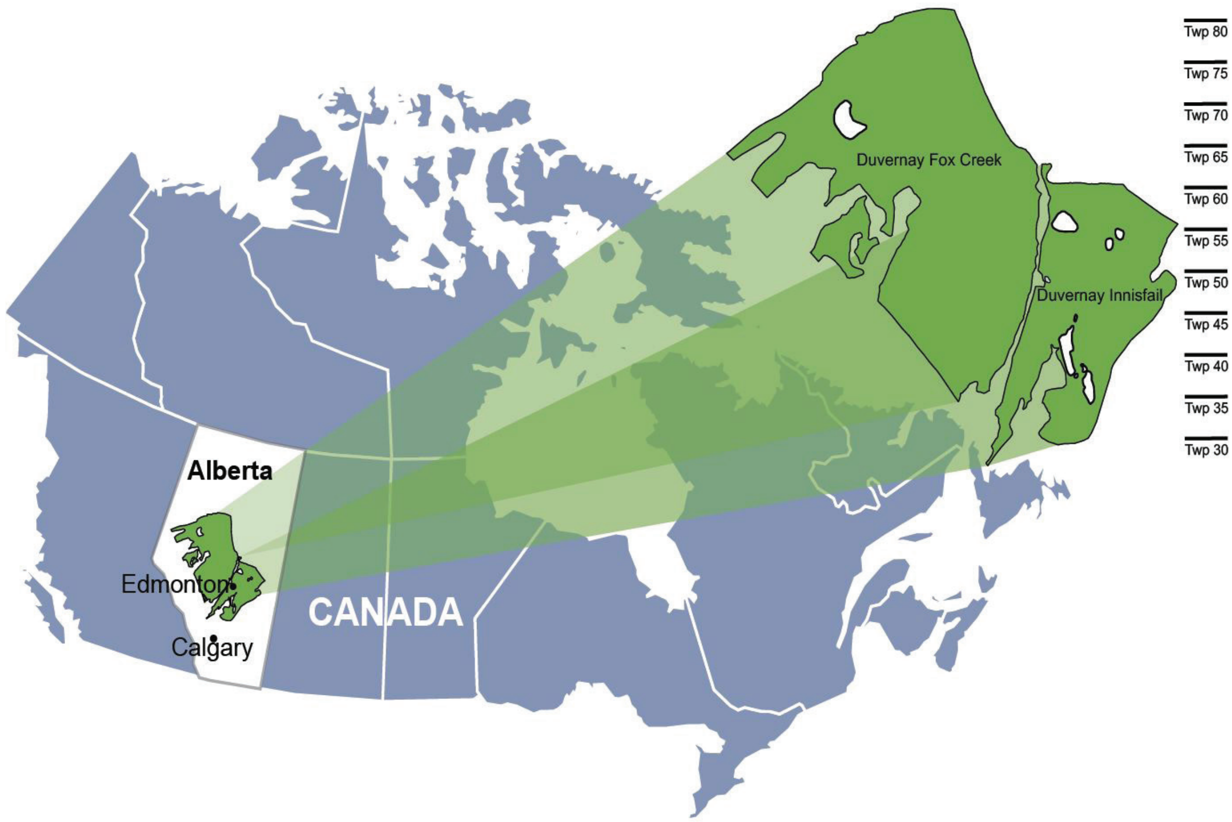

Figure 1. Duvernay depositional extent in central Alberta, Canada

and Duvernay Innisfail is the smaller play in the southeast and exists in the Devonian East Shale Basin (Figure 2). Additional information on the geological plays can be found in Section 2.2.

While the Duvernay covers a large extent, for evaluation purposes, only the productive areas have been subdivided into three assessment areas: Kaybob in the north portion of the extent, Edson-Willesden Green in the central portion of the extent, and Innisfail in the south portion of the extent (Figure 2). These assessment areas were divided based on similar geological characteristics and current development trends. The assessment areas are not to be confused with Alberta petroleum fields that share names.

Activity and reserves for the Duvernay have been evaluated and expressed across the Duvernay extent in this report. However, to account for heterogeneity across the extent, activity and reserves have also been reported by the assessment areas outlined in Figure 2. The Duvernay geological overview contained in this report was completed for the Kaybob and Edson-Willesden Green assessment areas.

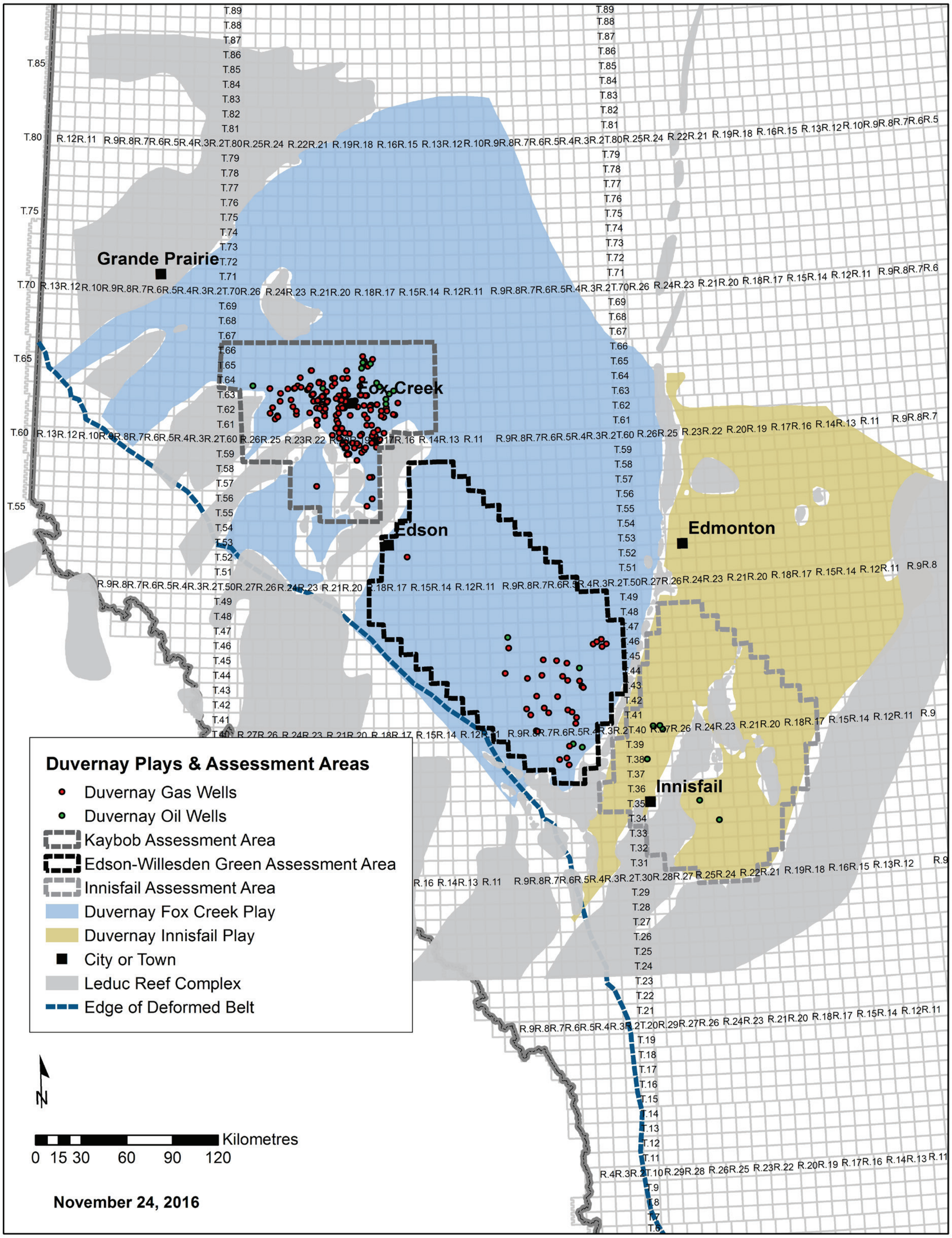

Figure 2. Duvernay plays and assessment areas

2 Geological Overview

2.1 Geology

The Duvernay is a geological formation found over most of central Alberta that was deposited during the Upper Devonian Period, over 372 million years ago (Rokosh et al., 2012). The Duvernay sediments were deposited on the slope, base-of-slope, and distal basinal areas surrounding the coexisting Leduc Formation reefs.

In the Fox Creek play, the Duvernay overlies the green shales of the Majeau Lake Formation; in the Innisfail play, the Duvernay Formation conformably overlies the Cooking Lake Formation. In the Innisfail play, the Duvernay interfingers with the associated Leduc reefs, thickening depositionally upslope towards the Leduc buildups, where its lithology more closely resembles the lower Ireton Formation (Glass, 1990). The upper contact of the Duvernay Formation is conformable with the overlying Ireton Formation, making it difficult to pick from wireline logs (Glass, 1990). In areas south and east of the Peace River Arch, the Duvernay conformably overlies the Waterways Formation (Glass, 1990).

The Duvernay is the source rock for the conventional hydrocarbon reservoirs in the Leduc reefs, the Swan Hills buildups, the Nisku and Grosmont platform carbonates, and for other clastic reservoirs, such as the Gilwood and Granite Wash sands. The Duvernay-sourced oil migrated as far as the Keg River carbonates on the edge of the Late Cretaceous sub-basin northeast of the Peace River Arch in the northeastern Alberta subsurface (Creaney et al., 1994).

The Duvernay dips to the southwest, with structural elevations ranging from approximately 900 metres (m) below sea level in the northeast to approximately 3600 m below sea level near the deformed belt (Appendix 2). Depths to the top of the Duvernay range from 1700 to 5000 m below ground surface.

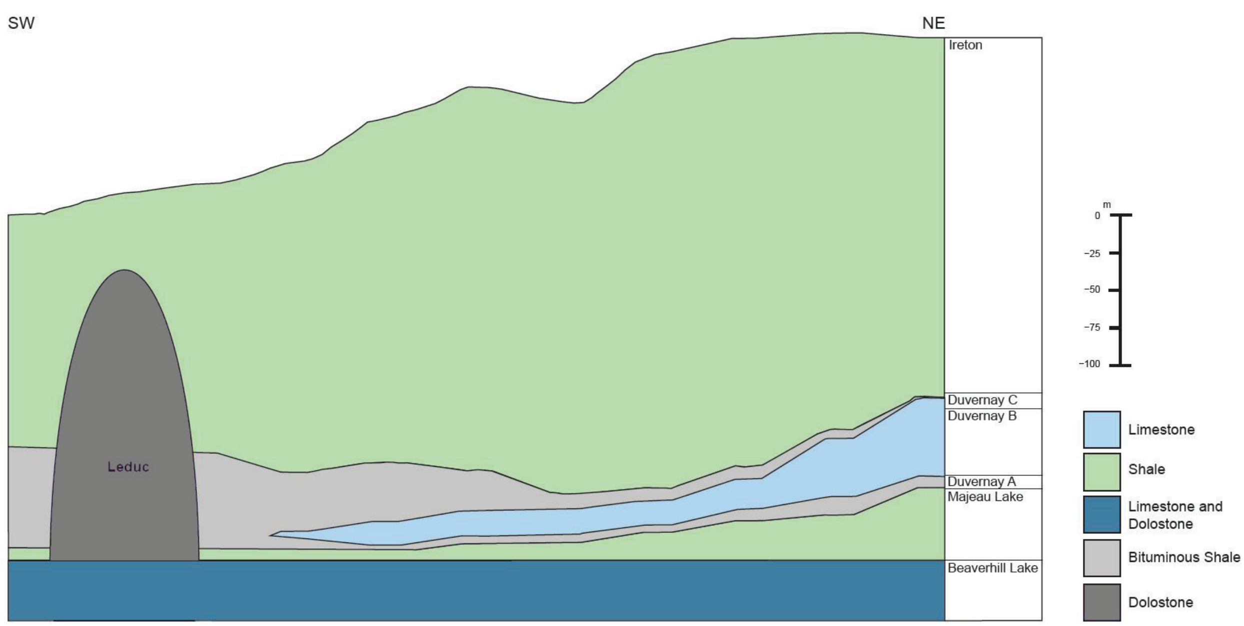

Figure 3. Schematic cross-section showing the informal Duvernay lithostratigraphic members

The AER subdivides the Duvernay into three informal lithostratigraphic members: A shale, B carbonate, and C shale (Figure 3). The A & C shale members are the target zones for development, while the B carbonate member may restrict the propagation of hydraulic fractures when it exceeds a critical thickness, and is considered to be nonreservoir.

The overall thickness of the Duvernay ranges from 2 m to 99 m. The B carbonate thickness ranges from 0 m to 66 m, while the A & C shale combined thickness ranges from 0 m to 62 m (Appendix 2).

2.2 Geological Plays

A geological play is a set of known or postulated oil, gas, or both accumulations (pools and deposits) within a petroleum system sharing similar geological, geographic, and temporal properties, such as source rock, migration pathways, timing, trapping mechanism, and hydrocarbon type (Appendix 1).

The Duvernay play boundaries correspond to two sub-basins that existed during deposition, about 380 million years ago during the Upper Devonian Period. The West Shale Basin matches the Fox Creek play and the East Shale Basin matches the Innisfail play (Figure 2). They are separated from each other by the Leduc-Rimbey-Meadowbrook reef trend, which was presumably rooted on a basement-associated paleo-bathymetric high. Reefs of this time period are referred to as the Leduc Formation, and the Duvernay was deposited between the reefs and on top of a carbonate shelf referred to as the Cooking Lake Formation.

The Duvernay within both plays was deposited in a marine basin environment and is within an overpressured regime. Both of the plays are composed of calcareous mudstone and carbonate, with a higher proportion of carbonate found in the Innisfail play. Insitu fluids in the Fox Creek play range from gas to oil, while oil is present in the Innisfail play.

2.3 Geological Parameters

Geological parameters, including porosity, porosity thickness (PhiH), total organic carbon (TOC), and brittleness index, were calculated for two of the three assessment areas. Due to the complexity in the Innisfail assessment area, a geological evalution has not been completed. The P90, P50, and P10 parameters for these two assessment areas are summarized in Table 1. Maps of the distribution of these parameters are provided in Appendix 3.

Table 1. Duvernay geological parameters

		Kaybob			Edson-Willesden Green		
Parameter	**Units**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
Porosity	%	7.0	8.5	9.5	7.0	8.0	10.0
Porosity-thickness	m	1.5	3.0	4.0	1.0	1.5	2.0
Total Organic Carbon	Weight %	3.0	4.0	5.0	3.5	4.5	5.5
Brittleness Index	%	43	49	54	45	47	50

2.4 Geological Prospectivity

When choosing drilling locations and optimizing completion strategies, operators may consider a number of geological factors that control prospectivity in the Duvernay. The amount of hydrocarbons and how the rock will respond to hydraulic fracturing is influenced by carbonate thickness, the porosity, the TOC, and the brittleness. To identify regions of greater prospectivity within the Fox Creek play, these four factors were combined and normalized by their range with equal weighting in terms of contribution to prospectivity. Figure 4 shows that Duvernay shales are regionally heterogeneous, and based on this analysis, the geologically most optimal area for prospectivity is around the Town of Fox Creek.

2.5 Expected Fluid Regions

In addition to mapping the Duvernay and its geological parameters, petroleum geologists can predict the fluids occupying the pore space of the rock. In an organic-rich shale deposited in a marine basin like the Duvernay, the organic material is expected to be mostly derived from phytoplankton and algae. This type of organic material, called Type II kerogen, will produce both oil and natural gas when buried and exposed to elevated pressure and temperature. The relative amount of oil versus natural gas produced will depend mostly on the temperature the rocks are exposed to.

The temperature at which the maximum rate of hydrocarbon generation is achieved is commonly called T_{max}. Rock analysis can be performed to determine T_{max}, which can be used to estimate the expected fluid type encountered at that location in the reservoir. For 35 wells in the Fox Creek play area, T_{max} data was analyzed and the expected fluid types were mapped, resulting in expected fluid regions (Figure 5). This map is considered accurate on a regional scale, but local variations in geological history and organic material-type make actual production quite variable, especially near fluid boundaries. As well, the type of organic matter in the Duvernay can produce oil and natural gas simultaneously over a range of temperatures.

Fluid regions may continue to be revised based on new information obtained from operators and additional core analysis data. Additional information on T_{max} can be found in Appendix 3.

When the prospectivity map of Figure 4 is combined with expected fluid regions of Figure 5 and knowledge of present and forecasted commodity prices, drilling costs, etc., one can understand historical patterns of development and begin to make reasonably constrained projections of development over a moderate time horizon.

3 Development History

The Duvernay Formation was first defined by geological staff at the western division of Imperial Oil Limited (1950) for dark grey to brown, bituminous shales in wells drilled near the town site of Duvernay, east-central Alberta. The reference well in Alberta is the Anglo Canadian Beaverhill Lake No. 2 11-11-050-17W4M well.

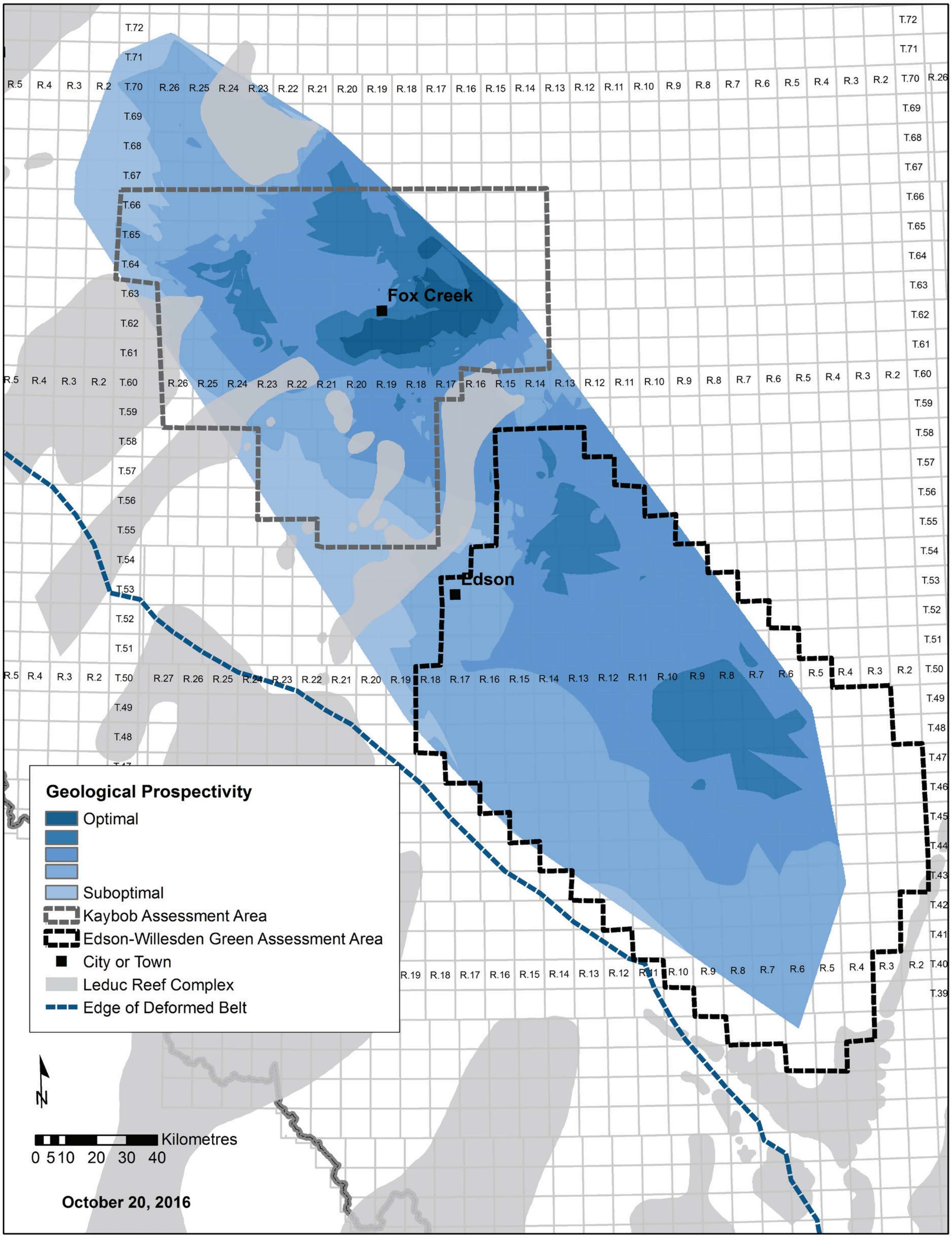

Figure 4. Geological prospectivity

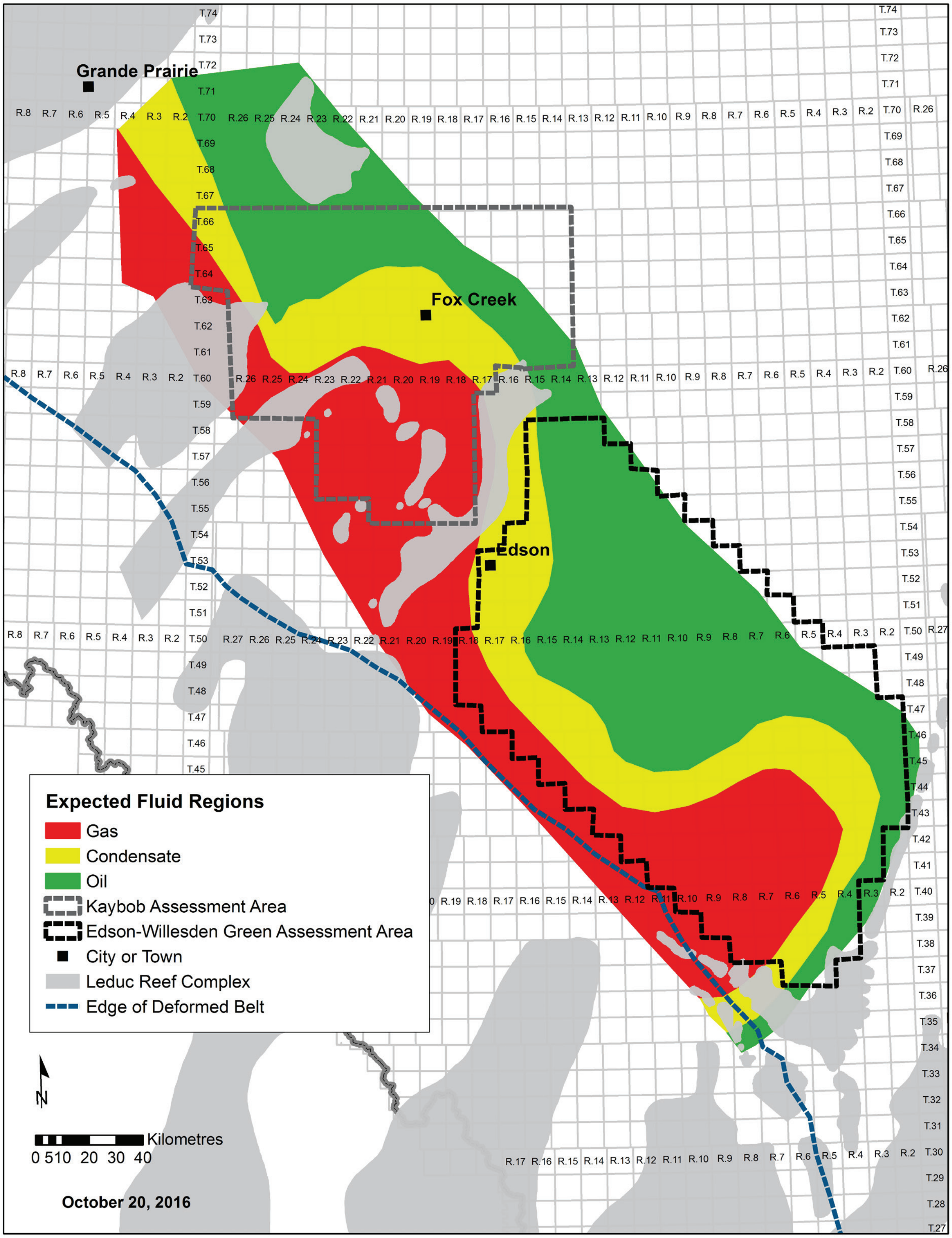

Figure 5. Expected fluid regions based on T_{max} analysis

Development in the Duvernay began in 2011 with horizontal multistage fracturing and has steadily increased (Figure 6 and Figure 7).

In the Duvernay, the Kaybob assessment area has experienced the most development, with 197 gas wells and 11 oil wells drilled as of the end of December 2015. Table 2 outlines activity and six-month initial production rates, and Table 3 provides cumulative production by fluid type and assessment area.

As shown in Table 2, wells in the Kaybob area are achieving greater six-month initial production rates than the Edson-Willesden Green and Innisfail areas for each of the P90, P50, and P10 cases. Another consideration for the variability in six-month initial production may be operational constraints such as pipeline capacity or wells having been rate restricted.

The production volumes listed in Table 3 correspond with Figure 8, which illustrates the increased production and development in the Duvernay by assessment area from 2012 to 2015. The Kaybob assessment area is the current focus of development, with 130 new wells placed on production in 2014 and 2015, versus 17 in the Edson-Willesden Green and 5 in the Innisfail assessment areas. When comparing fluid production in terms of million barrels of oil equivalent, the Kaybob area yields the most condensate production, at 35% of total production, whereas condensate accounts for just over 20% of production in Edson-Willesden Green. Oil production is the focus in Innisfail, where it accounts for nearly 90% of total production.

Life cycle development in the Duvernay is classified as being in an intermediate to late stage of testing, with some operators well into the piloting phase, with abundant growth potential in the near future.

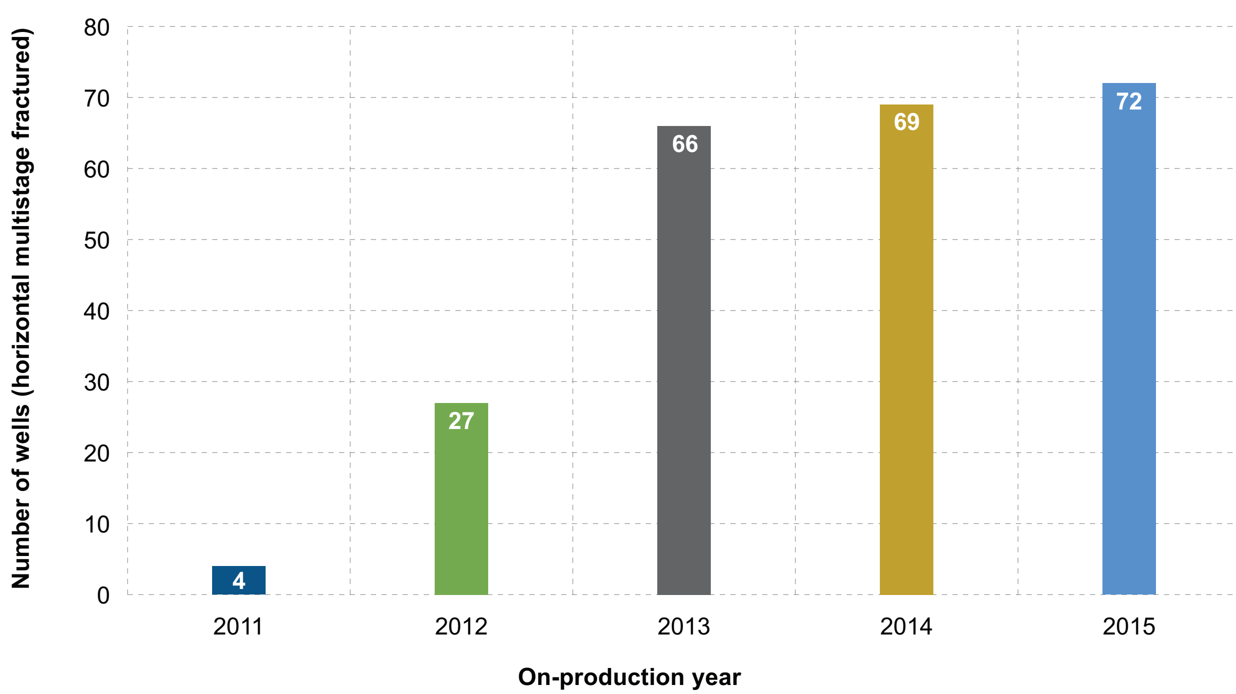

Figure 6. Duvernay horizontal multistage fractured wells by on-production year

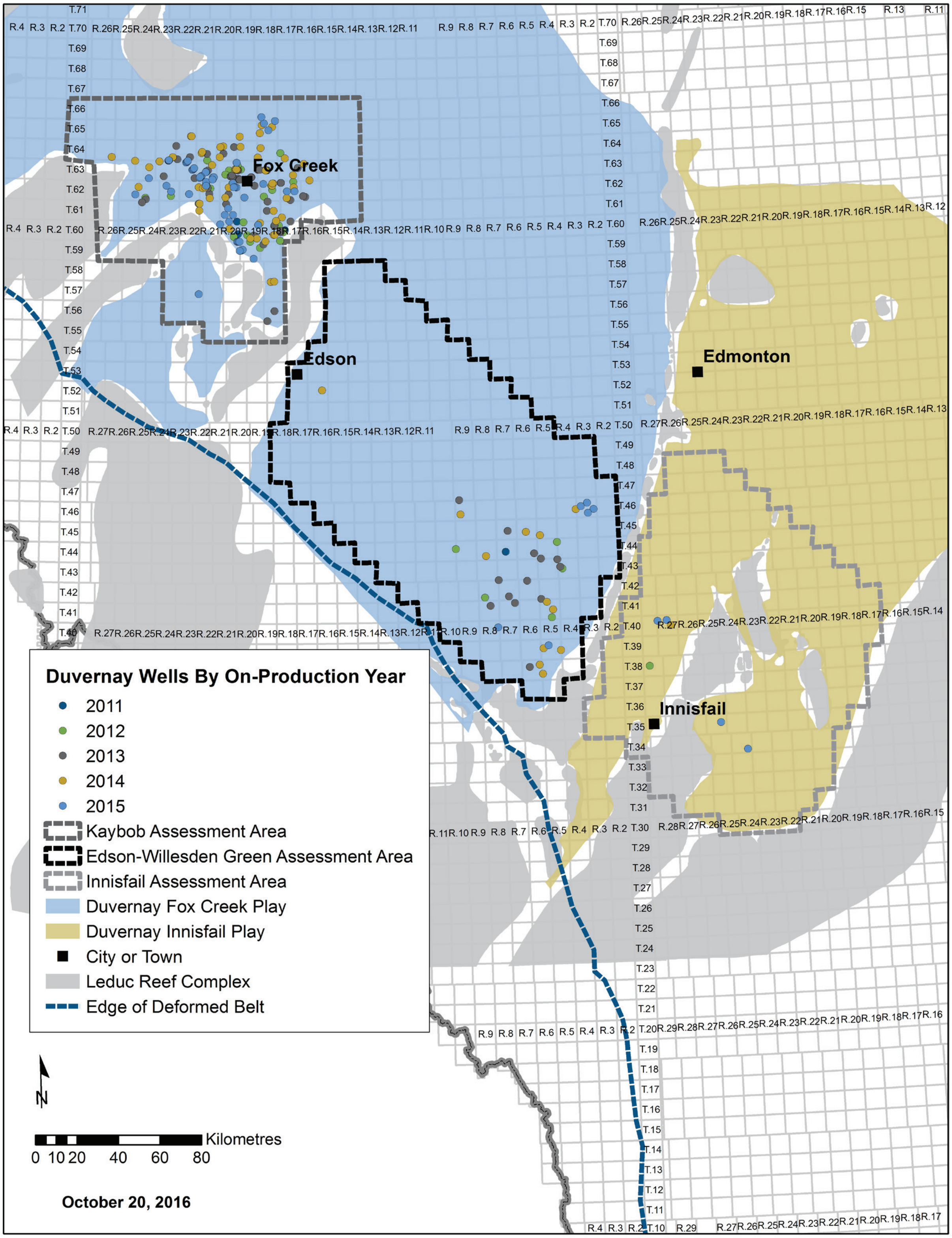

Figure 7. Horizontal multistage fractured wells in the Duvernay area by on-production year

Table 2. Duvernay well activity by assessment area

	Kaybob	Edson-Willesden Green	Innisfail
Total number of wells	197	39	6
Number of wells on stream	187	39	6
P90 6 month IP (Mboe/d)	30	21	27
P50 6 month IP (Mboe/d)	61	38	34
P10 6 month IP (Mboe/d)	112	79	41

Table 3. Duvernay production by fluid type and assessment area (Mboe)*

	Kaybob				Edson-Willesden Green				Innisfail			
	Oil	Cond	Gas	No. Wells	Oil	Cond	Gas	No. Wells	Oil	Cond	Gas	No. Wells
2012	19.1	129.3	400.7	21	2.6	16.60	184.55	5	11.4	0.0	1.6	1
2013	104.8	1 227.2	2 022.5	53	36.3	156.11	554.29	13	32.3	0.0	4.4	0
2014	326.2	3 660.4	5 684.1	65	86.2	383.40	1 234.39	12	66.3	0.0	10.5	1
2015	593.0	5 594.1	11 476.5	62	173.3	548.58	1 995.39	6	153.9	0.0	19.4	4

MMboe – thousand barrels of oil equivalent (6:1 basis)

Production values do not account for wells that are reporting condensate as a recombined gas stream (as per the *Oil and Gas Conservation Act*). As such, the condensate and gas volumes listed may not accurately reflect actual field condensate and gas production in the Duvernay.

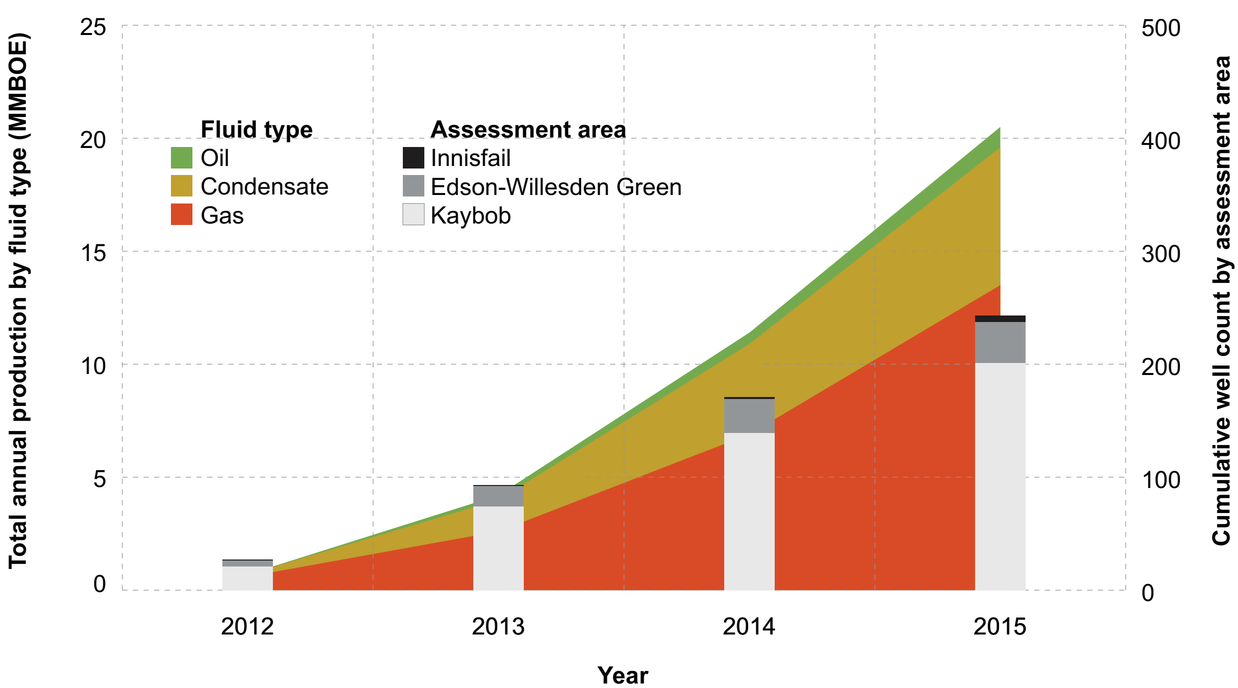

Figure 8. Annual Duvernay production by fluid type and cumulative well count by assessment area

Production will likely increase if energy economics improve and stay favourable. In the meantime, it is expected that operators will continue to pilot different completion techniques to further optimize production and hold their lands in anticipation of market turnaround. Future development will target the condensate-rich regions of the Duvernay.

4 Resource Classification & Categorization

Until now, the AER classified Alberta's reserves based on the report of the Joint Task Force on Uniform Reserves Terminology from the Inter-Provincial Advisory Committee on Energy (IPACE) in 1978. IPACE focuses on traditional, or conventional, pools and does not fully account for the complexities of modern, or unconventional, plays.

In 2015, the AER created a resource classification system to accommodate Alberta's unique resource base. Adapted from the *Canadian Oil & Gas Evaluation Handbook* (COGEH; SPEE, 2007) and Resources Other Than Reserves (SPEE, 2015), the AER's resource classification framework provides guidelines for differentiating resources according to trapping mechanism. These broad categories allow the AER to manage each resource independently with reserves assessment methods that are fit for purpose.

Six resource categories are identified within the framework, as shown in Figure 9.

Each resource category has a unique set of properties and requirements for characterizing the resource and evaluating reserves. Based on this framework, the Duvernay exists primarily within the AER's shale resource category, and contains both shale gas and oil resource types, based on the specified trapping mechanism of adsorption on kerogen, in addition to being present in pores and fractures. The Innisfail assessment area may contain resource that also exists within the AER's low permeability category (e.g., tight carbonates).

	Resource Category					
	Conventional	Low Permeability	Shale	Coalbed Methane	Bitumen	Coal
Resources Type	API Oil Types Natural Gas Natural Gas Liquids	Tight Gas Tight Oil Tight Hybrid	Shale Gas Shale Oil	Coalbed Methane	Oil Sands Carbonate-hosted Bitumen	Subbituminous Bituminous metallurgical Bituminous thermal
Trapping	Buoyancy/seal	May be buoyancy/seal, relative permeability effects, or other factors	Adsorption on kerogen, in pores and fractures	Adsorption in coal micropores, fractures	High viscosity	Accumulates in thick organic deposits
Reserves Evaluation	Deterministic COGEH Volumes 1 and 2	Probabilistic COGEH General, SPEE Monograph 3	Probabilistic COGEH General, SPEE Monograph 3	Probabilistic COGEH Volume 3, SPEE Monograph 3	Probabilistic IPACE	Deterministic CRIRSCO General

Figure 9. AER resource classification framework

The COGEH provides a basis for classification and categorization of all components of petroleum resources and is the reference document for *National Instrument 51-101: Standards of Disclosure for Oil and Gas Activities in Canada* (Alberta Securities Commission, 2015). Aspects of the COGEH have been adopted by the AER to communicate with clarity to external stakeholders using common terminology.

As per the COGEH, reserves are estimated remaining quantities of petroleum anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data—and the use of established technology. Reserves are further classified according to the level of certainty associated with the estimates and may be subclassified based on development and production status (SPEE, 2007).

The AER categorizes reserves into two types: total proved reserves and total proved plus probable reserves. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. For proved plus probable reserves, it is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves (SPEE, 2007).

5 Reserves Evaluation Methodology

The evaluation of reserves is limited to wells licensed for production from the Duvernay. The producing wells evaluated were based on public, nonconfidential wells on stream before January 1, 2016 (Appendix 4). Forecasts have been estimated using a thirty-year economic limit of January 1, 2046. Some wells were not included in this report due to uncertainty regarding production.

This report does not include the valuation of marketable hydrocarbon reserves. Evaluations were completed on the hydrocarbon stream at the point of measurement and not the point of sale. This report focuses on the hydrocarbons produced as opposed to the economic value attached to those hydrocarbons.

Estimates of ultimate recovery have been derived using monthly production data without the use of bottomhole flowing pressure data. Ideally, daily production would be used with the addition of high resolution bottomhole flowing pressures; however, these data were not available at the time of evaluation because the AER does not currently require them to be submitted with production data.

For the purpose of this document, condensate is defined as the free hydrocarbon liquid at the point of measurement in wells classified as gas producers.

Undeveloped reserves were assigned based on the reasonable assumption that undeveloped locations will be drilled in the next five years and that there are no physical restrictions to drilling the proposed locations (SPEE, 2010). While the AER has not considered in-depth economics of the play, it has considered areas being targeted based on factors that control geological prospectivity in the Duvernay (see Section 2.4 for more information) and industry activity. Given the current low commodity price environment, undeveloped reserves were only assigned to future potential locations directly offsetting existing producers within the core liquids-rich regions of each assessment area. Undeveloped reserves were not assigned within the natural gas regions of the Kaybob or Edson-Willesden Green assessment areas. These assumptions may be revisited annually to ensure that the methodologies used are aligned with current economic realities.

5.1 Developed Producing Reserves

As stated in SPEE, 2007, "developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty."

5.1.1 Gas Reserves

Deterministic estimates were derived using a long-duration linear flow model to characterize linear flow and validate production data points. Flow regime diagnostics were used to identify linear flow patterns and to help define the decline parameters used for traditional decline equations. Due to the ultra-low permeability and heterogeneous nature of the Duvernay, and the techniques used to complete wells in the formation, it is expected that linear flow will be the predominant flow regime for most, if not all, of the life of the well (Lee, 2015). Based on the expectation of long-duration linear flow periods in these wells, traditional forecasting methods commonly used in more conventional reservoirs are not appropriate in the Duvernay.

5.1.1.1 Flow Regime Diagnostic Plots

Two individual diagnostic plots were used to assess production history and identify flow regimes for approximately one-third (64) of the total population (179) of developed producing wells in the Kaybob assessment area. The following diagnostic plots were used in this analysis:

- the square root time plot $1/q$ vs $\sqrt{t}$ (IHS, 2014), where q is thousand cubic feet per day (Mcf/d) and t is days
- the material balance time (MBT) plot log q vs log MBT (Lee, 2015), where $MBT = Q/q$, Q is thousand cubic feet (Mcf), and q is Mcf/d

The square root time plot is used as a first check to eliminate early time data where the well may have had insufficient time to establish a defined flow regime or where the production may still be representative of initial fracture fluid cleanup. This plot was also used to help clean up data in preparation for the MBT analysis. Other production data that are not suitable for further analysis may be identified by points that do not clearly fall onto the initial established trend of the data, as identified in Figure 10.

If there is a change in the slope of the data, it may indicate a change to the operating conditions or a transition to a second linear flow regime. If there is an upwards curvature of the data in the later life of the well, the trend may be indicative of a transition to boundary-dominated flow. Any other points that do not follow the general trend of the data may be excluded from any further analysis.

The validated data points were then assessed using the log rate versus log MBT plot. Data quality checks were performed for all MBT data points to ensure that trends were increasing over time and that any anomalous increases or obvious outliers were excluded from further analysis. A negative half (−0.5) slope on the MBT plot indicates linear flow (Lee, 2015). Data points are further validated using this plot by determining whether or not the early time data falls within the linear slope trend. This is illustrated in Figure 11.

Any data that occurs before the negative half slope trend emerges is believed to be associated with initial wellbore clean up and is excluded from further analysis. In some instances, no identifiable negative half slope trend can be seen, which may be due to operator constraints on the well or data quality issues. In these cases, these trends could not be further validated without consideration of flowing pressure data.

Late time data can also be analyzed using the MBT plot, based on a negative-one (−1) slope trend (Lee, 2015). If it is possible to fit a reasonable negative one slope to sufficient data, the well may have entered boundary-dominated flow (BDF). Based on the wells evaluated for this report, no discernible negative one slope trends were observed, which indicates that the wells reviewed to date have not yet reached BDF. It is anticipated that the sooner a well reaches BDF, the lower the estimated ultimate recoverable (EUR) for that well will be. Some of the major considerations affecting the time that it takes for a well to reach BDF include well spacing, fracture spacing, fracture propagation, fracture permeability, and matrix permeability.

Data points identified as being valid linear flow points are refined until a match between the square root time and MBT plots is made. As wells were evaluated using this process, it was observed that in most instances, it was necessary to weight the validated points on the square root time plot slightly higher than the MBT plot.

Two additional plots were considered for linear flow diagnostics:

- the Yu plot $\ln \frac{q_0}{q}$ vs log t where q_0 is defined as peak rate (Mcf/d; Yu, Lee, Miocevic, Li, & Harris, 2013) and and q is Mcf/d
- the Duong plot log q/Q vs log t (Duong, 2010), where Q is Mcf and q is Mcf/d

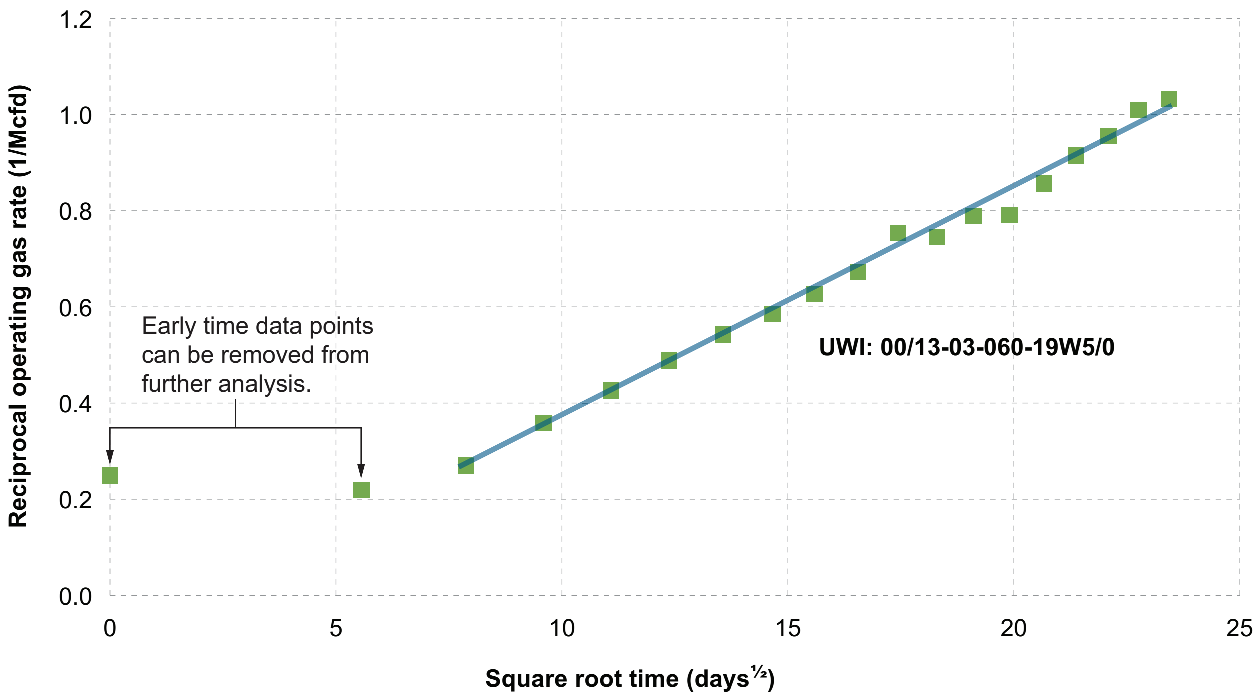

Figure 10. Flow regime diagnostics: square root time plot

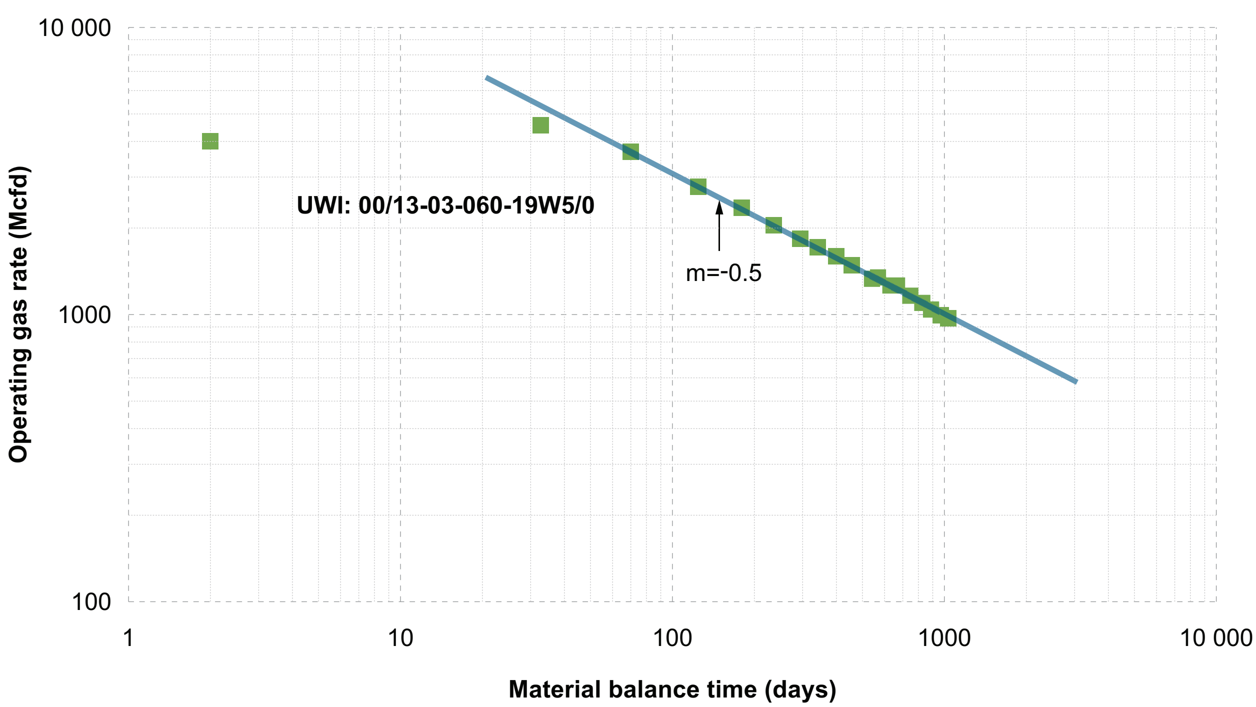

Figure 11. Flow regime diagnostics: MBT plot

Both of these diagnostic plots exhibit a straight-line trend. These trends can be helpful in identifying linear flow. It is important to note that these plots should not be used to replace either the square root time plot or the MBT plot.

5.1.1.2 Decline Curve Analysis

Given the large range of uncertainty associated with EUR in unconventional shale resource plays, the AER adopted the long-duration linear flow model and modified hyperbolic decline curve analysis approach, which has been widely used for reserve evaluations (Lee, 2015).

For the data points determined to be in linear flow, a traditional decline model was fitted to the data using a decline (b-factor) of 2 to represent the linear flow behavior of the well (Lee, 2015). Since BDF could not be identified in any of the Duvernay wells evaluated, limiting effective declines of 5%, 10%, and 15% were used as a transition point to BDF. From each of the respective transition points, a traditional decline model with b-factor of 0.5 was applied for gas wells, and 0.3 for oil wells (Lee, 2015).

Each decline was extended 30 years (to January 1, 2046). To better describe the full uncertainty distribution, the two-segment decline using a limiting effective decline of 10% was assumed to represent the P50 decline for the well, with 15% representing the P90 decline, and 5% representing the P10 decline. The limiting effective declines of 15%, 10%, and 5% were used in order to capture the full range of values that could be obtained from the decline methodology described above. An example of the results from the decline methodology is provided in Figure 12. Since BDF was not observed in any of the Duvernay wells, forecasts may be assessed annually.

Given that production from unconventional resources remains in transient linear flow for long periods of time, the assumption associated with traditional decline curve analysis that a well is in BDF, is not appropriate in the Duvernay. If traditional decline curve analysis is applied to wells producing from shale reservoirs, with no consideration of flow regimes, results may be overestimated. A list of the wells evaluated is included in Appendix 4.

5.1.1.3 Monte Carlo Simulation

In order to capture the uncertainty associated with reserve estimates in the Duvernay, a Monte Carlo simulation was created to determine probabilistic EURs for each individual well. The Monte Carlo simulation predicts the monthly cumulative production of a well out to a predetermined month. The monthly cumulative production is then correlated to deterministically derived EUR values. Using this correlation, individual probabilistic EUR values were calculated in the Kaybob assessment area. In effect this methodology creates a time-series simulation in order to determine a probabilistic EUR for individual wells. The Monte Carlo simulation was restricted to the Kaybob assessment area due to the lack of well control in the other assessment areas. An example of the output EUR distribution is provided in Figure 13. A workflow for creating and implementing the Monte Carlo simulation is included in Appendix 5.

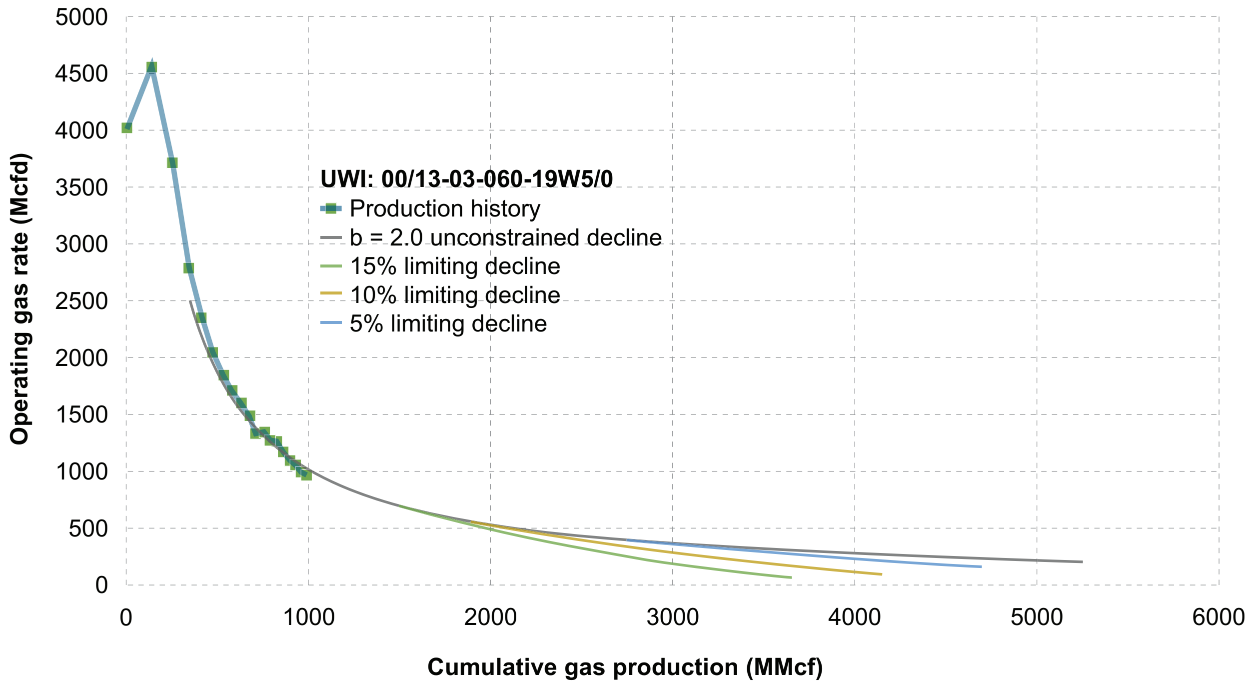

Figure 12. Multisegment decline with 15%, 10%, and 5% limiting declines

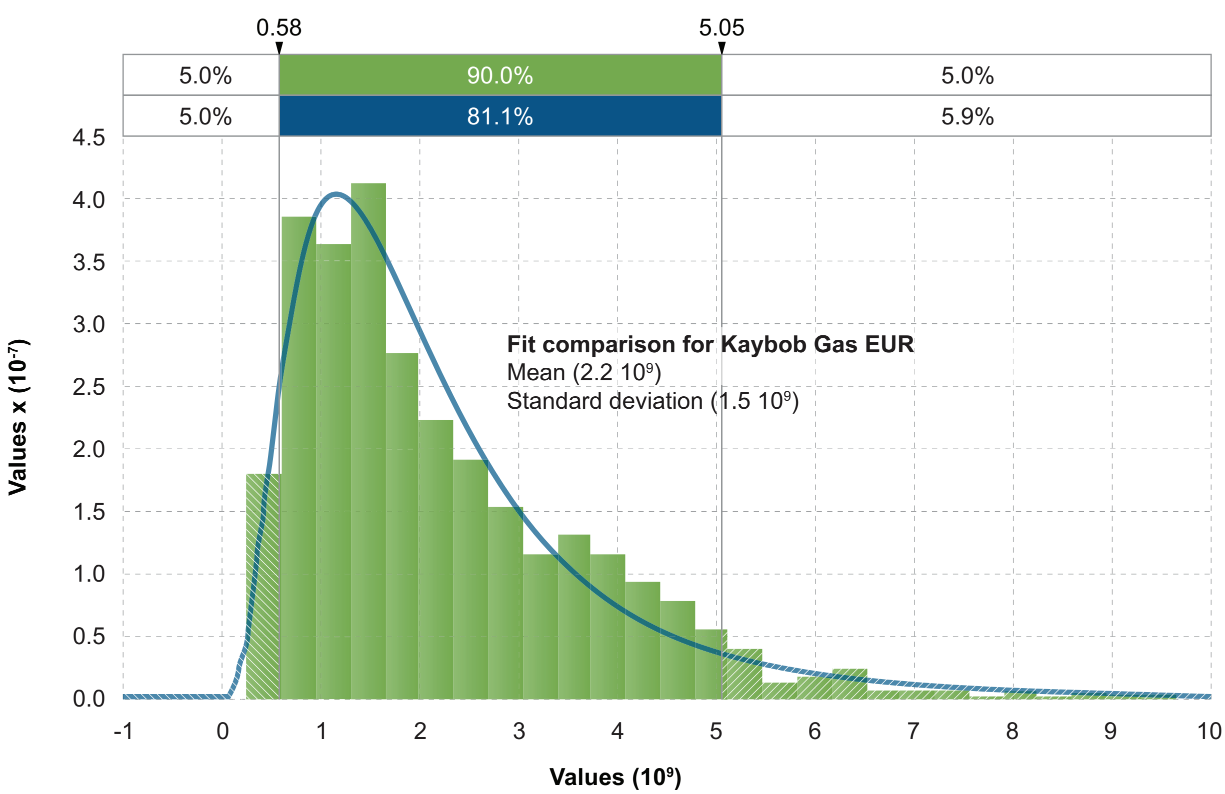

Figure 13. Kaybob Monte Carlo simulation results: gas EUR (Bcf)

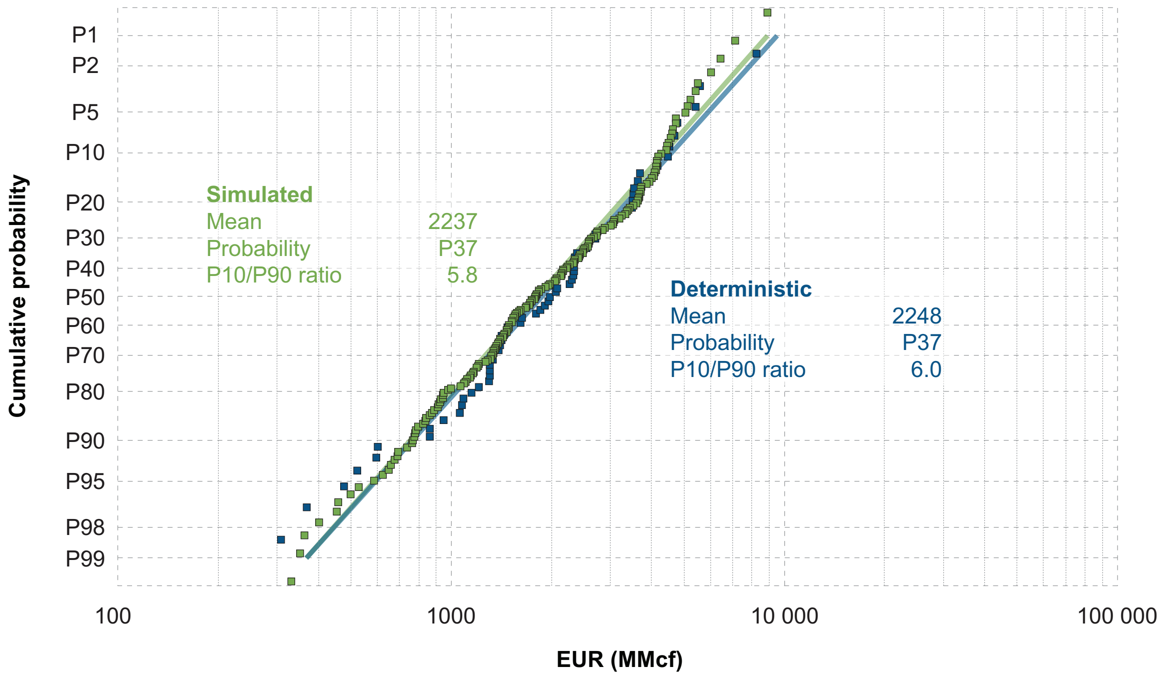

Figure 14. Comparison of deterministic and probabilistic EURs

The Monte Carlo simulation results were validated against the deterministically forecasted EURs to ensure that the probabilistic estimates were reasonable given the distribution of EUR across the assessment area. The distributions of deterministic and probabilistic EUR forecasts are outlined on the log-cumulative probability plot in Figure 14.

Figure 14 shows that the simulated EURs closely mirrors the individually forecasted deterministic declines. This demonstrates that the probabilistic methodology described above is able to produce comparable results to the deterministic long-duration linear flow model applied to the manually validated linear flow data. This is to be expected because the input for the time-series equations used to calculate the probabilistic EURs are the deterministic declines. As a result of this analysis, a range of probabilistic EUR values were determined for the total population of producing Duvernay wells in the Kaybob assessment area. This methodology allowed for reserves to be assigned to wells that initially could not be evaluated using the deterministic methodology due to data quality issues or insufficient production history.

5.1.2 Condensate Reserves

To address liquids production associated with the Duvernay, the AER adopted the methodology for predicting condensate production outlined by Yu (2014). The methodology requires the use of cumulative condensate-gas ratio (CGR_{cum}) versus cumulative gas production (G_p) plots.

A straight-line trend was fitted to the most recent trend of the data for wells with sufficient data, as shown in Figure 15. Condensate recovery was estimated by first extrapolating this linear trend to the well's estimated ultimate gas recovery to get an estimate for CGR_{cum}.

When condensate was not reported separately from the gas stream, this methodology could not be used to predict CGR_{cum} values at abandonment. Caution should be exercised when applying this method to publicly reported data. Several instances exist where gas and condensate may have initially been reported as separate streams until a move at some point in the well's history to combined stream reporting. In these cases, linear trends in CGR_{cum} that result from the lack of condensate reporting should be ignored in the analysis. Condensate dropout in the reservoir, or in the wellbore if the gas velocity is not sufficient to carry the liquid to surface, will also result in a drop in the CGR_{cum} trend. An example illustrating a drop in the established CGR_{cum} trend is shown for well 00/06-11-063-20W5/0 in Figure 16.

The distribution of CGR_{cum} values derived using this methodology was mapped spatially across the Kaybob assessment area as shown in Figure 17. The area was subdivided into CGR regions based on the CGR_{cum} at abandonment (30 year) values. CGR_{cum} abandonment intervals of 50 bbl/MMcf were used to subdivide the regions. The total population of wells was then grouped based on which region they are located. Each well group was then assigned a final CGR_{cum} value equal to one-third of the specified CGR_{cum} range rounded to the nearest integer. For example, wells in the 100–150 bbl/MMcf region were assigned a final CGR_{cum} value of 117 bbl/MMcf. The final CGR_{cum} value for each group was then multiplied by the gas EUR for each respective well within the group to estimate a final condensate EUR.

Applying the one-third methodology described above generally gave reasonable results. Wells with unreasonable results were identified and re-evaluated independently.

There were 146 wells identified within the potential retrograde condensate and volatile oil regions. Wells with CGR_{cum} values of less than 50 bbl/MMcf were assumed to be primarily natural gas wells. Figure 17 is strictly based on the production data that has been submitted to the AER. Due to issues associated with field condensate being reported as a recombined gas stream, there is some variation between Figure 17 and the expected fluid regions as shown in Figure 5. However, both figures may be refined in the future as new information becomes available.

5.1.3 Oil Reserves

The deterministic workflow described in Section 5.1 was applied to any oil wells with sufficient production data to determine oil EUR. Very few oil wells could be reliably forecasted using this methodology. Due to the limited sample size and insufficient production history, a Monte Carlo simulation could not be applied to the oil wells. As such, oil EURs were assigned to the remaining oil producers using the deterministically evaluated wells as approximate analogues. A list of oil wells and associated EURs is provided in Appendix 4.

5.2 Developed Nonproducing Reserves

Developed nonproducing reserves are those reserves that either have not been on production or have previously been on production but are shut in, and the date of resumption is unknown (SPEE, 2007).

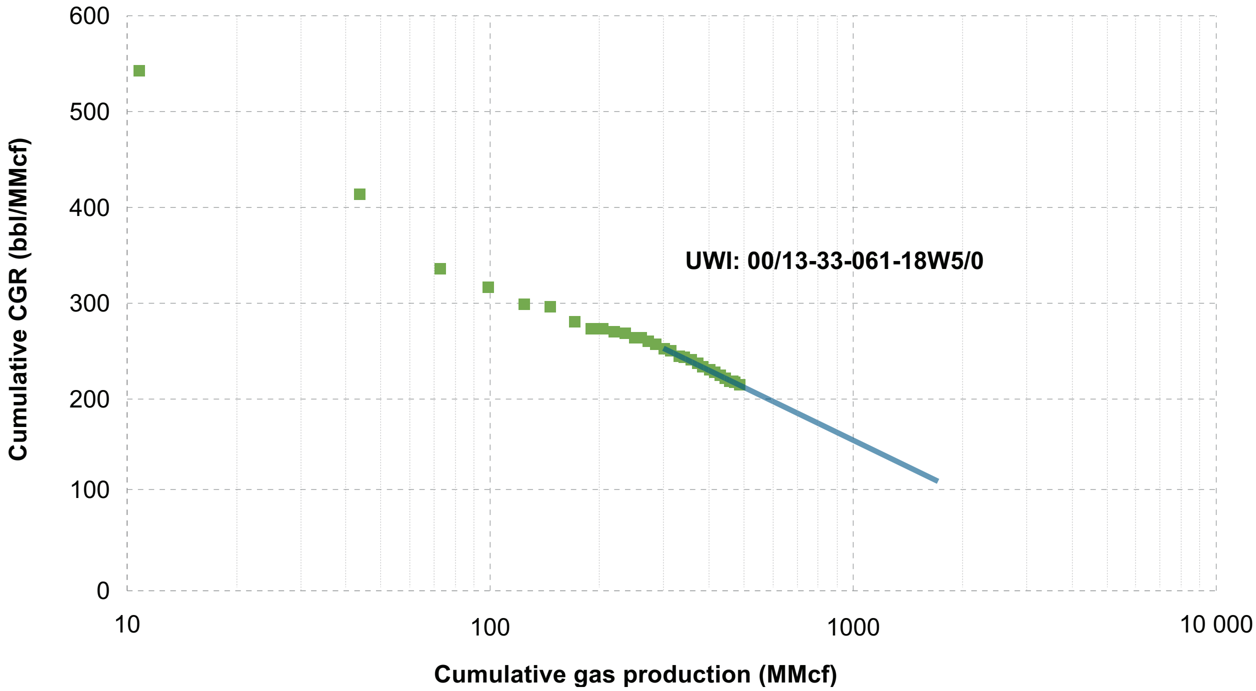

Figure 15. CGR$_{cum}$ vs cumulative gas production plot

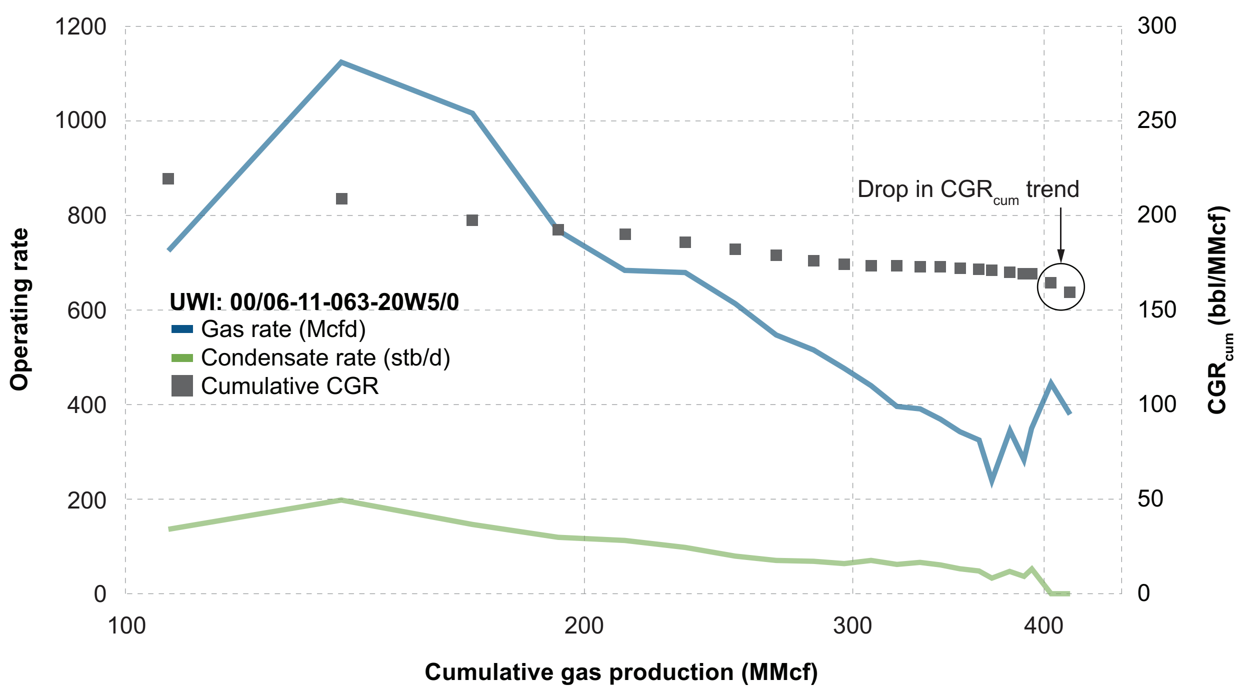

Figure 16. CGR$_{cum}$ vs Cumulative gas production plot with secondary trends

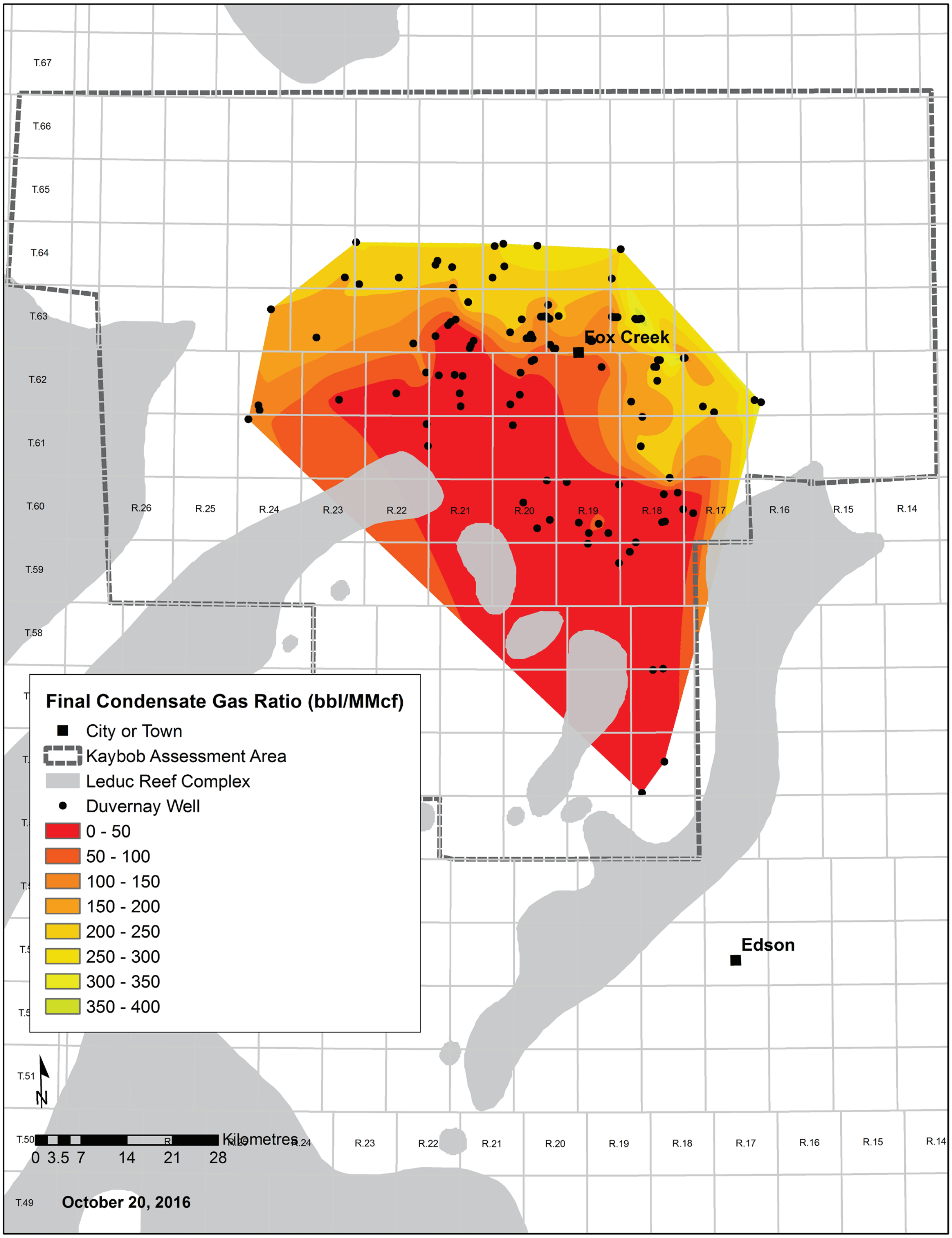

Figure 17. Kaybob distribution of final CGR

Currently there are several wells in the Duvernay with the well status of “Standing”. These wells are drilled, cased, and tied in, but are not currently on production. If a well has had the status of “Standing” for more than a year, it is assumed that this well will be abandoned and will no longer produce. In this case the initial reserves of the well are equal to its reported production and the remaining reserves are equal to zero.

5.3 Undeveloped Reserves

As stated in SPEE (2007), “undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must meet the requirements of the reserves category (proved, probable, possible) to which they are assigned.”

Rose (2016) suggests limiting undeveloped reserves locations to offsetting development spacing areas that are reasonably certain of production when drilled. SPEE (2010) recommends assigning undeveloped reserves to several spacing units beyond the immediately offsetting acreage. Given the current low commodity price, this assessment considered both approaches. Undeveloped reserves were only assigned within the oil and condensate regions of each assessment area because large quantities of volatile oil or retrograde condensate are needed to remain economic during low price environments.

The number of wells to be drilled during a high cost, low commodity price environment was projected by multiplying the number of wells drilled in the first six months of 2016 by a factor of 1.30. This factor was calculated by analyzing published capital expenditure information for the Kaybob area, in conjunction with the knowledge that the majority of wells are drilled in the first six months of a calendar year. This yielded a projected well count of 71 new wells for the entire 2016 calendar year. Then, assuming the current high cost, low commodity price environment will continue for the next five years, it was estimated that development within the oil and condensate regions of the Kaybob assessment area would not exceed 360 wells.

As operators continue to advance downspacing and completion pilots within the core liquids-rich areas of the resource, it is believed that trends reflecting the favoured wellbore drilling and completion parameters will begin to emerge, and drilling programs will become more focused to achieve additional drilling and completion efficiencies. Given these considerations, trends of interwell spacing and horizontal lengths were analyzed to determine a scenario suitable for assigning undeveloped locations in the Duvernay.
To evaluate well spacing, developed well pads in the Duvernay were analyzed for favoured horizontal wellbore spacing trends (where a pad is defined as a surface hole location shared by four or more wells). Analysis of pad well spacing by completion year is illustrated in Figure 18.

Figure 18 shows that during the earlier stages of development, operators were favouring tighter interwell spacing between pad wells, but in 2015 spacing between pad wells began to increase (to 350–400 metres). As shown in Figure 19, a variation in horizontal well lengths between completion years was also observed.

Figure 19 shows that operators continued to vary the horizontal lengths of wells drilled between 2013 and 2015. In 2015, horizontal lengths of 2000 to 2200 metre were favoured.

The information from these trends were combined to form a resource recovery evaluation scenario. It was assumed that the development trend in the area would continue with the most common spacing regime of 350 to 400 metres per well, which equates to a well density of roughly four wells per section. Using typical lateral wellbore lengths of 2000 to 2200 metres, and an eight-well pad configuration, the equivalent of approximately three sections will be developed per pad (the 8/3 rule) regardless of wellbore orientation as shown in Figure 20.

As shown in Figure 20, the 8/3 rule assumes that each horizontal wellbore will intersect the equivalent of approximately 1.5 sections. If there will be four wells per developed section and each well intersects the equivalent of 1.5 sections, there must be eight wells per every three developed sections.

To determine the total number of undeveloped locations to assign to each assessment area, the number of developed sections was determined by counting the total number of sections that were intersected by an existing Duvernay wellbore in each assessment area. The total number of sections were then subdivided between the oil and condensate fluid regions for each assessment area. Using the 8/3 rule, the total number of sections in each fluid region were converted to a total number of wells to be drilled. Existing Duvernay wells were then subtracted from the total well count in each fluid region to determine the total number of undeveloped locations. The total number of undeveloped well locations by assessment area is outlined in Figure 21.

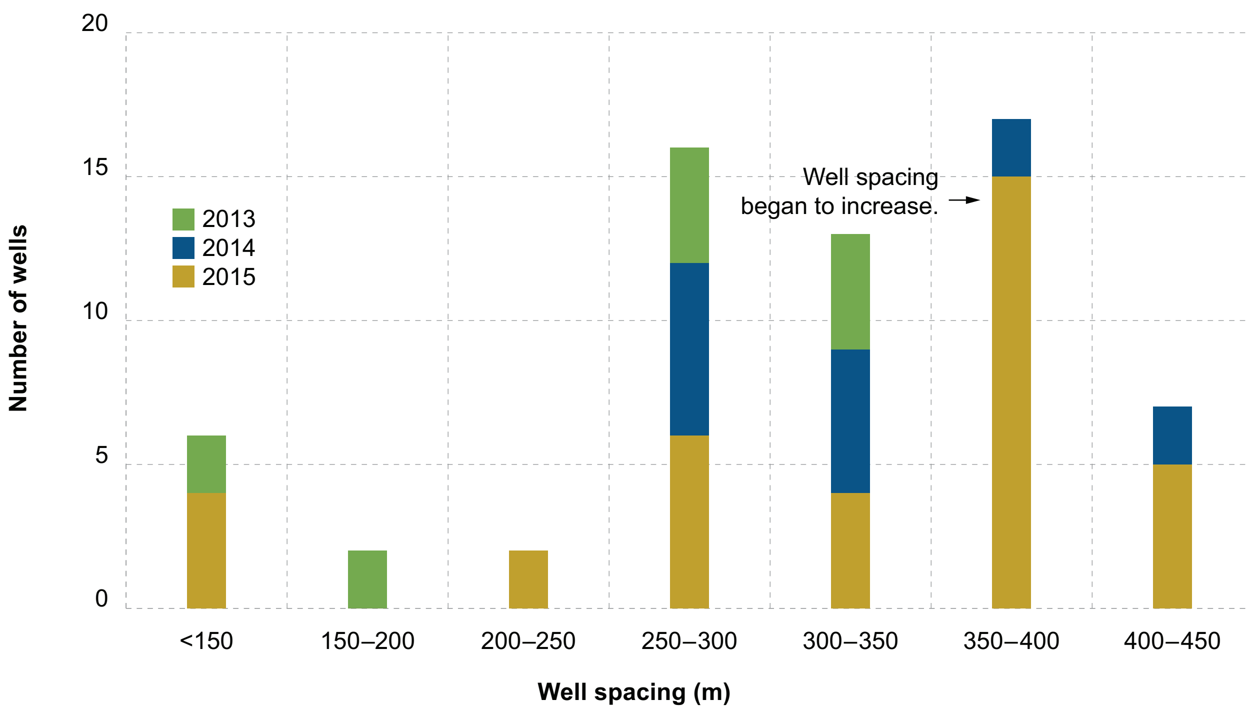

Figure 18. Kaybob pad well spacing by completion year

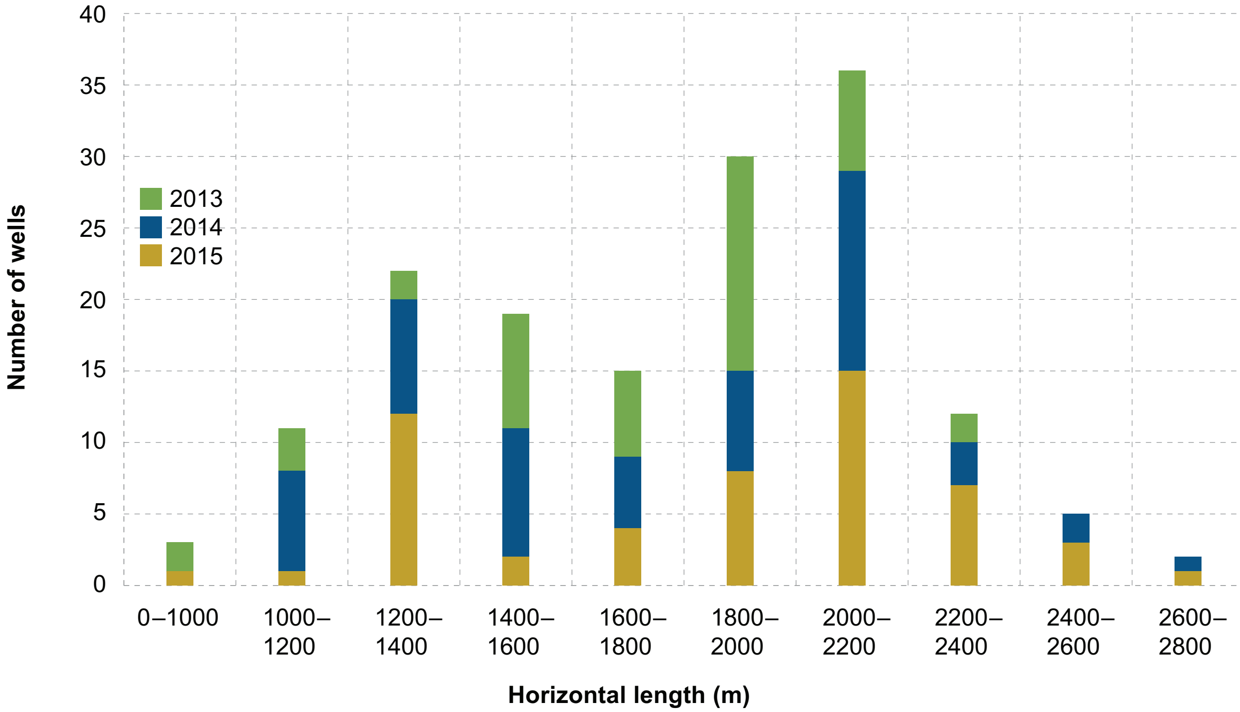

Figure 19. Kaybob horizontal wells lengths by completion year

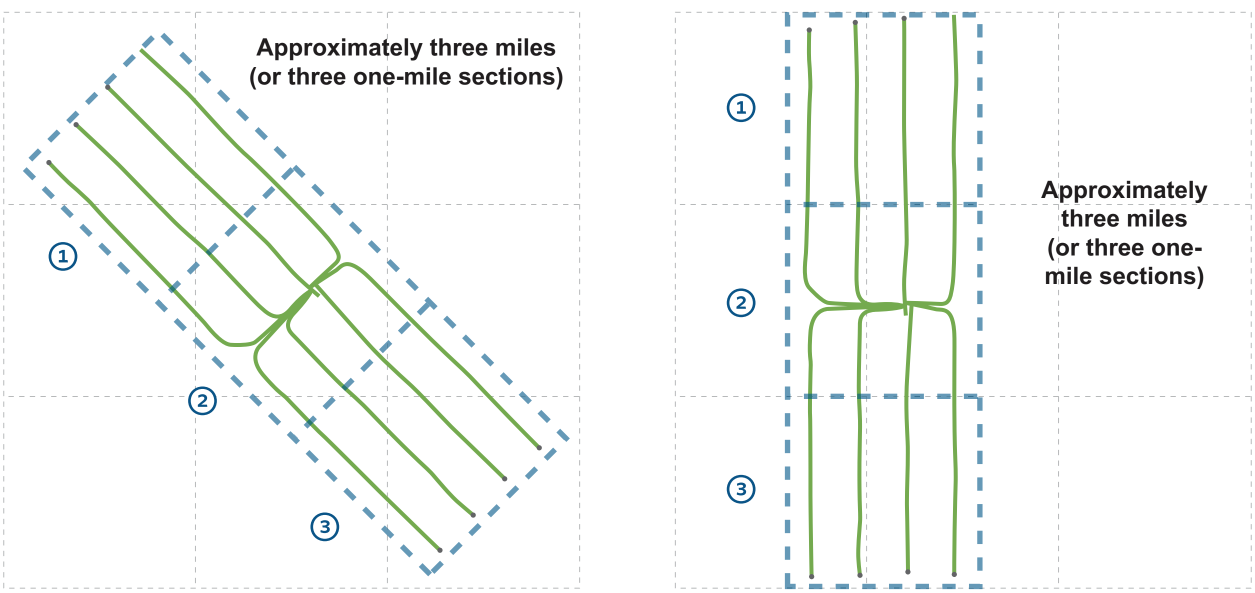

Figure 20. Eight-well pad configuration per three sections (8/3 rule)

Given the current low commodity price environment, undeveloped locations were only assigned to future potential locations directly offsetting existing producers within the core liquids-rich regions of each assessment area. Undeveloped reserves were not assigned within the natural gas regions of the Kaybob or Edson-Willesden Green assessment areas.

Undeveloped locations were reviewed to ensure they exist within the Duvernay resource extent and that there were no obvious surface constraints that may potentially affect future development. These assumptions ensure that undeveloped well locations are determined based on reservoir factors, economic considerations, and the suitability of surface locations, which aligns with the core principles outlined in the COGEH and SPEE (2010) evaluation guidelines.

5.3.1 Gas Reserves

Gas reserves were assigned to each of the 272 undeveloped locations in the Kaybob assessment area and the 80 undeveloped locations in Edson-Willesden Green assessment area using aggregated P90 and P50 EURs derived from the Monte Carlo simulation. Figure 22 outlines the input EUR distribution used to determine gas reserves for wells within the condensate region of the Kaybob assessment area.

The Monte Carlo simulation was run for 100 000 iterations, and the resulting distribution for the 272 undeveloped gas locations in the Kaybob assessment area is outlined in Figure 23.

Total proved and proved plus probable undeveloped gas reserves were determined by multiplying the total number of undeveloped well locations in the Kaybob assessment area (272) by the aggregated P90

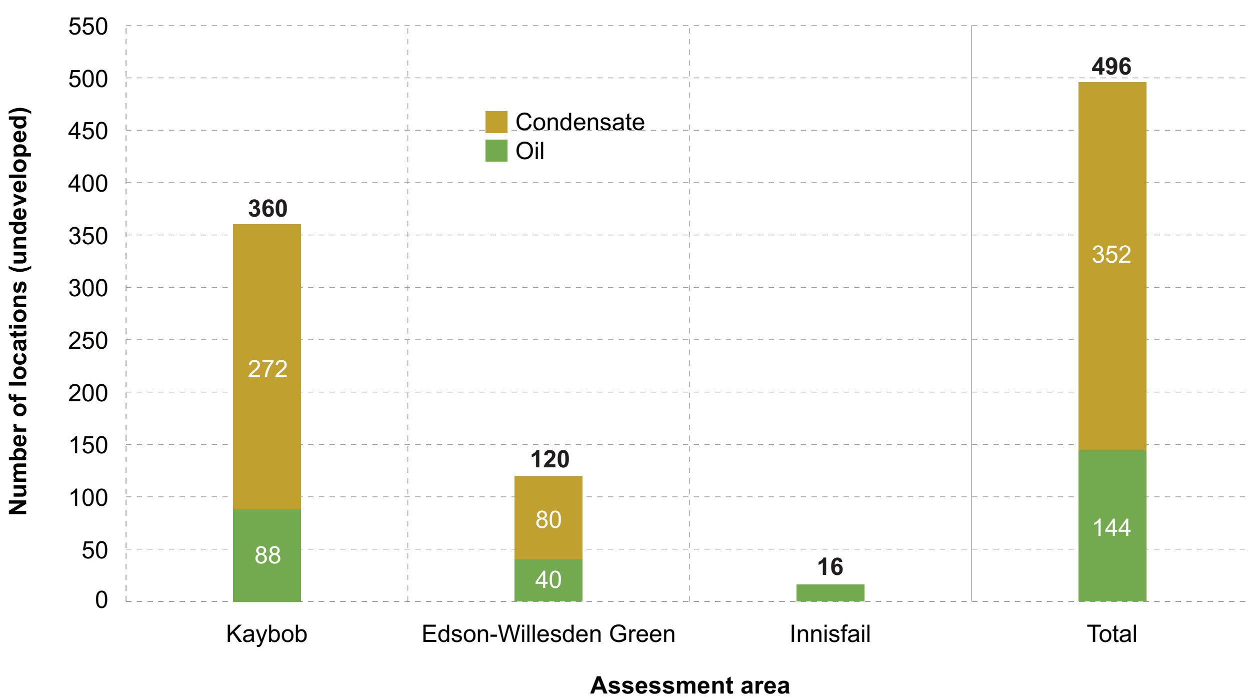

Figure 21. Undeveloped locations by assessment area

and P50 EURs, respectively. The EUR aggregation versus well count is outlined by the trumpet plot in Figure 24.

As shown in Figure 24, with increasing aggregated well count, the P90 EUR will increase and the P10 EUR will decrease. As described by Freeborn & Russell (2015), the increased certainty can be explained by example. As more wells are drilled, the likelihood that all of the new wells will have the lowest EUR becomes quite small. The likelihood that all of the new wells will have the highest EUR is also quite small. As such, the lowest expected EURs must increase as the well count increases, and the highest expected EURs must decrease as the well count increases. Or, as the number of samples increases, the 80% confidence interval of the mean decreases.

5.3.2 Condensate Reserves

Similar to the aggregation of gas EURs described in Section 5.3.1, CGR_{cum} abandonment values were also aggregated to the undeveloped well count of 272 for the Kaybob assessment area as shown in Figure 25. The same methodology was applied in the Edson-Willesden Green assessment area. The P90 and P50 aggregate gas EURs were multiplied by the P90 and P50 aggregate CGR_{cum} abandonment values to obtain P90 and P50 condensate EURs.

As shown in Figure 25, with increasing aggregated well count, the P90 CGR will increase and the P10 CGR will decrease.

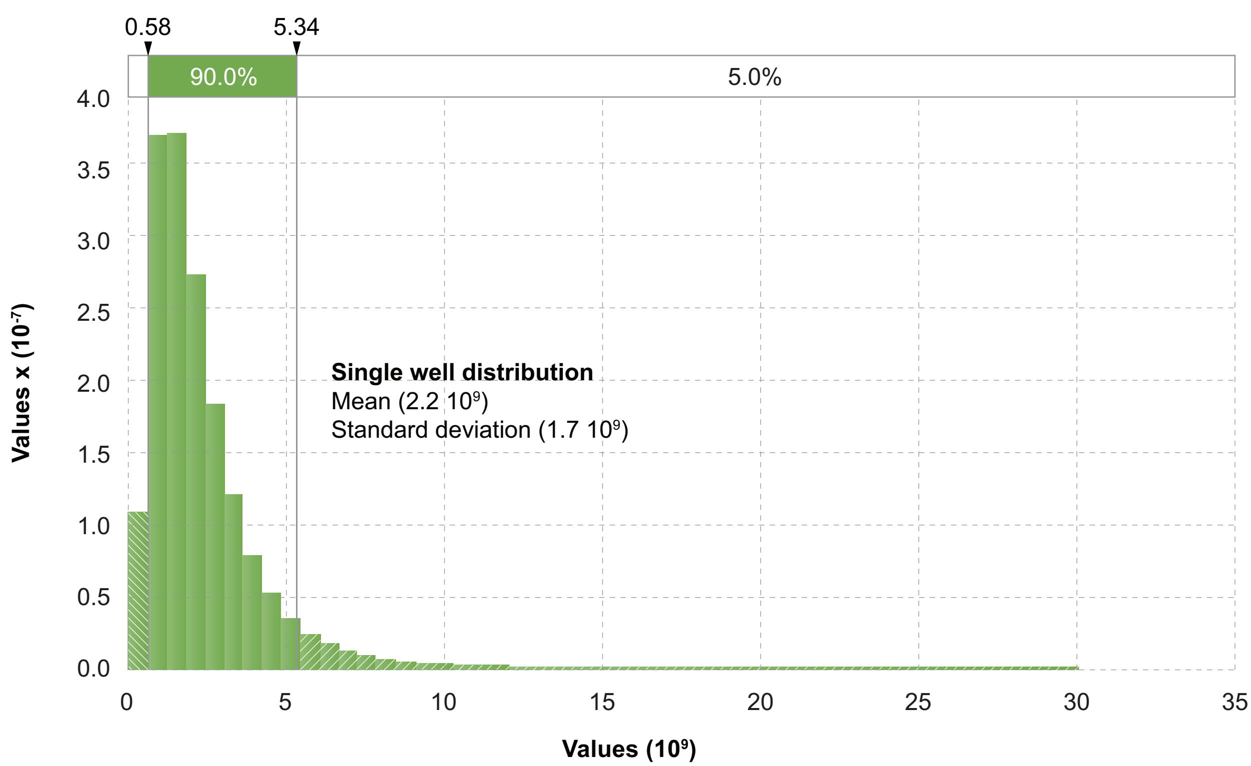

Figure 22. Kaybob input gas EUR distribution (Bcf)

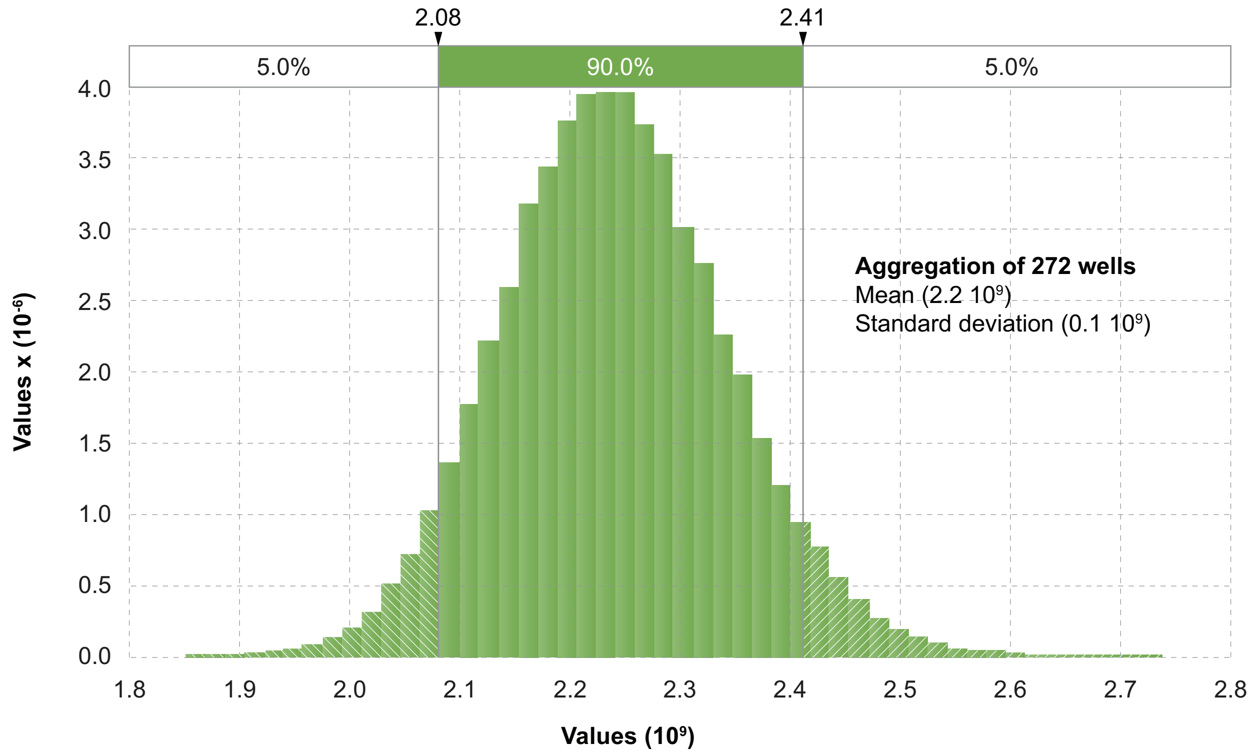

Figure 23. Kaybob resulting aggregate EUR distribution (Bcf)

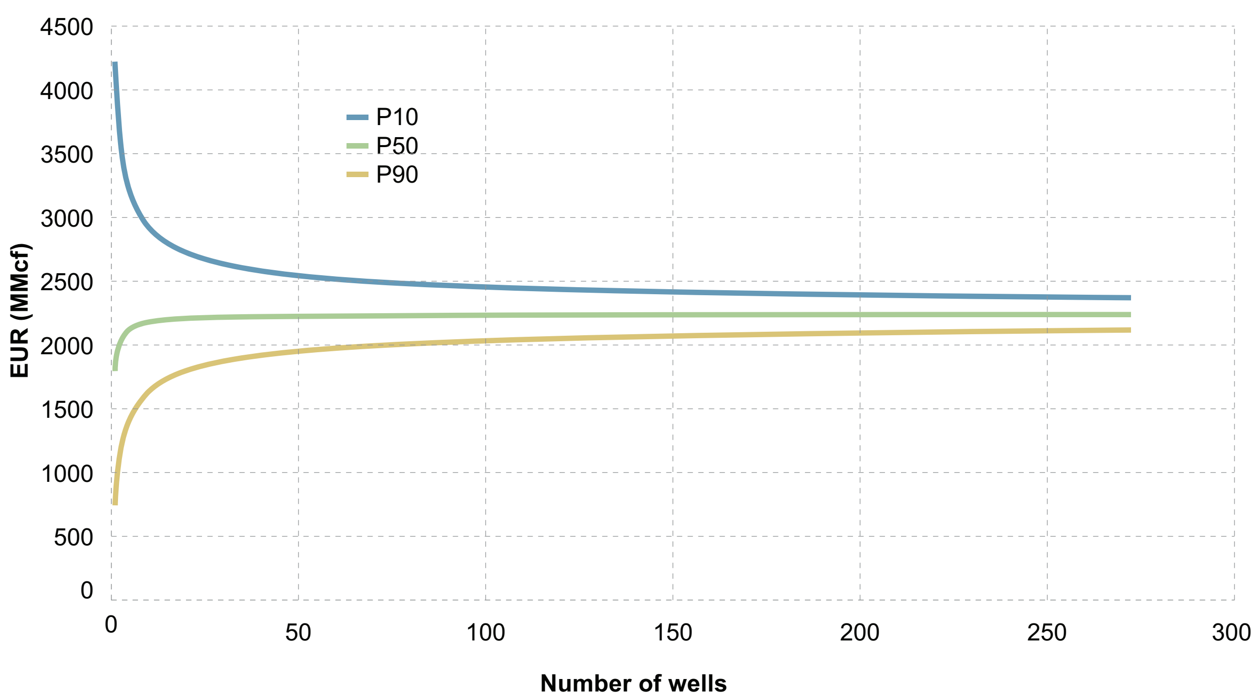

Figure 24. Kaybob aggregated gas EUR versus well count

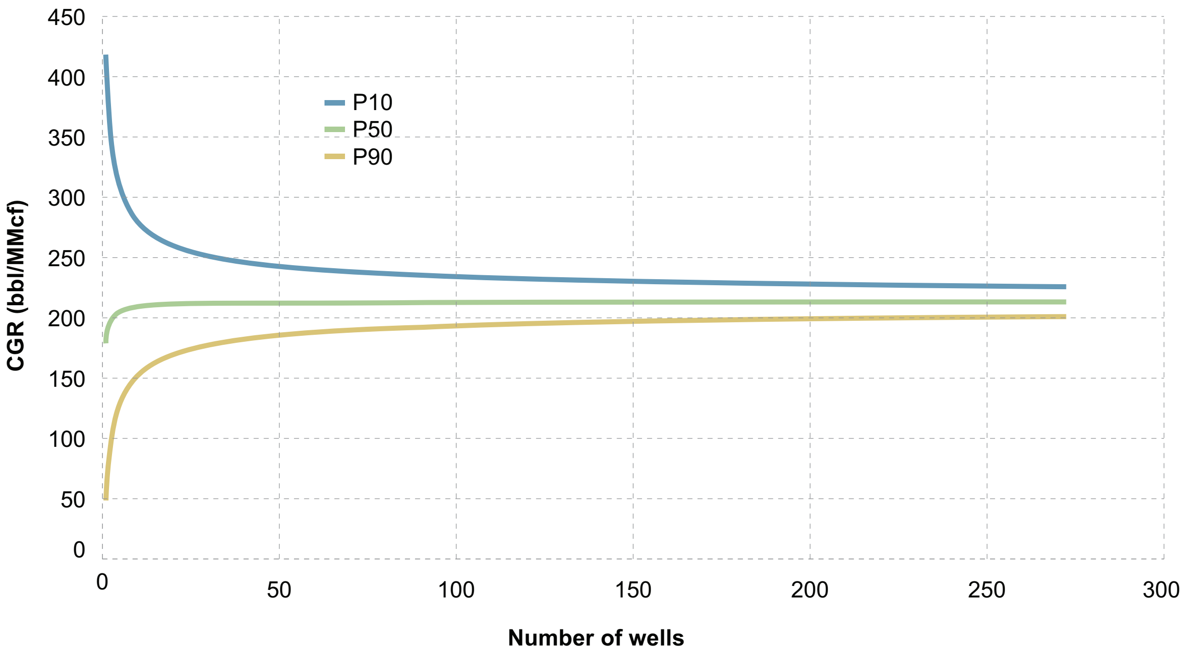

Figure 25. Kaybob aggregated CGR versus well count

5.3.3 Oil Reserves

Since there was not a significant sample of oil wells within the oil region to use as an input distribution to the Monte Carlo simulation, 90% of the mean of the P90 and P50 oil EUR per well distributions were assigned to the undeveloped oil locations for each respective assessment area in order to capture uncertainty.

6 Reserves Results

Duvernay reserves were estimated for oil, gas, and condensate by assessment area. Total reserves were determined by summing the results from each assessment area.

6.1 Total Duvernay Reserves

Total remaining proved reserves are 354 MMboe and proved plus probable reserves are 395 MMboe. The total initial and remaining proved and proved plus probable reserves are provided in Table 4.

Table 4 provides recoverable reserve estimates for the total Duvernay resource. Although probabilistic techniques were used to account for the large range of technical uncertainty associated with these estimates, uncertainty remains associated with geological and reservoir engineering constraints, recovery efficiencies, and additional economic factors. The combination of these factors with other social and environmental considerations, will ultimately determine the true growth potential of this resource.

The spatial distributions of P50 gas EUR and P50 CGR_{cum} have been provided as Figure 26 and Figure 27, respectively.

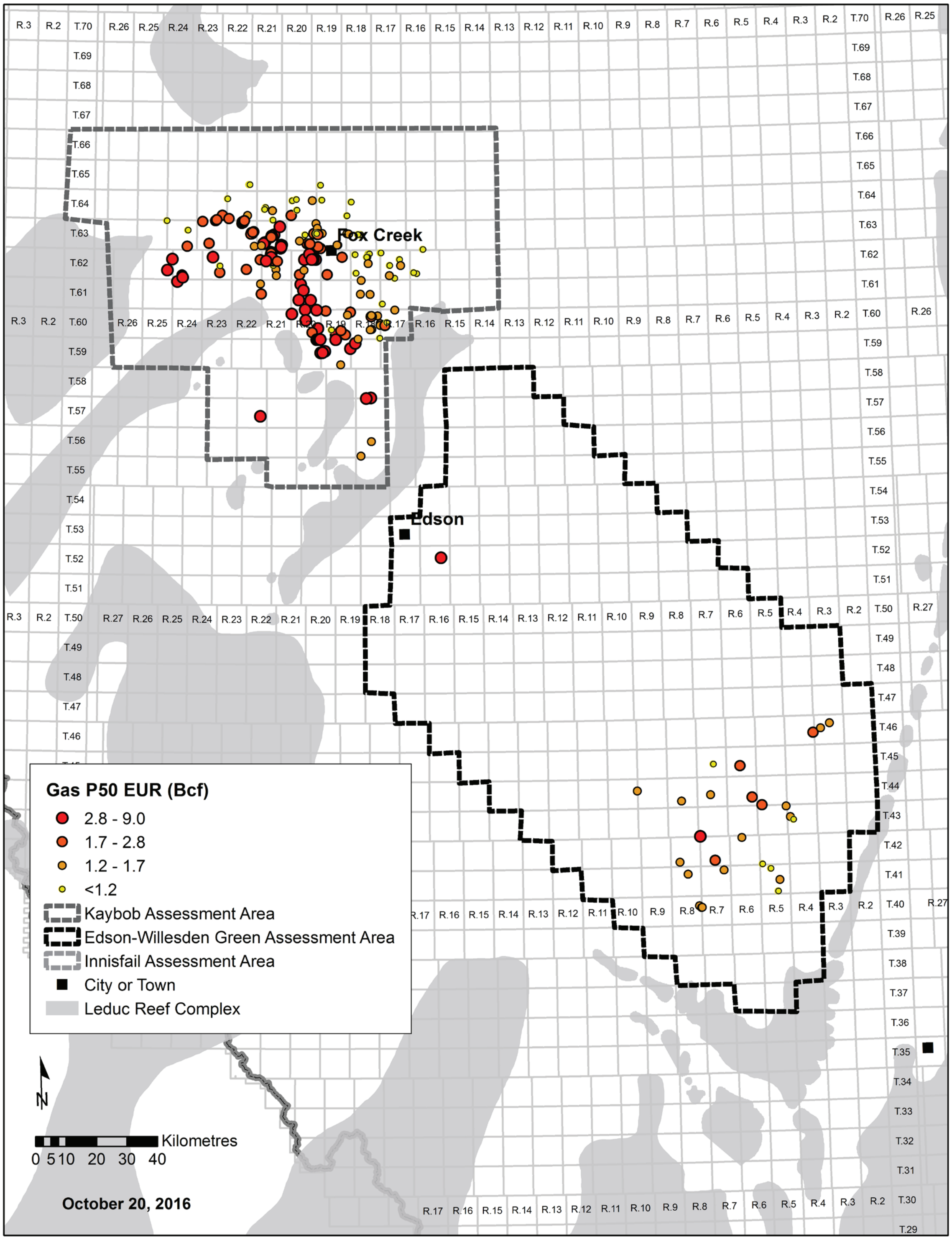

Figure 26. Duvernay P50 gas EUR

6.2 Duvernay Reserves by Assessment Area

Duvernay reserves were estimated for oil, gas, and condensate within the Kaybob, Edson-Willesden Green, and Innisfail assessment areas. The initial and remaining proved and proved plus probable reserves by assessment area are provided in Tables 5, 6, and 7.

7 Contingent Resources

The COGEH defines contingent resources as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. A contingency is any factor that prevents current commercial development of a discovered petroleum resource.

As described by (SPEE, 2015), technology development starts with an idea and progresses through different stages of testing to verify its technical and commercial viability. Each stage of the testing process may be characterized as to whether it has demonstrated technical or economic viability and is assigned a project maturity subclass according to its associated chance of development (SPEE, 2015).

The evaluation of resource recovery in the Duvernay is in the early stages and it is premature to identify the long-term economic viability of development. Therefore, the economic status for Duvernay resource recovery is “undetermined” (SPEE, 2015, Figure 2.2). Operators are field testing throughout

Table 4. Total Duvernay reserves effective January 1, 2016*

	Initial				Remaining			
	Oil (MMbbl)	Gas (Bcf)	Condensate (MMbbl)	BOE (MMboe)	Oil (MMbbl)	Gas (Bcf)	Condensate (MMbbl)	BOE (MMboe)
Proved								
Developed Producing	6	393	30	101	5	315	24	81
Developed Nonproducing	0	4	0	1	0	0	0	0
Undeveloped	29	737	121	273	29	737	121	273
Total	**35**	**1134**	**151**	**375**	**34**	**1052**	**145**	**354**
Proved + Probable								
Developed Producing	6	453	35	117	6	375	28	96
Developed Nonproducing	0	4	0	1	0	0	0	0
Undeveloped	32	783	136	299	32	783	136	299
Total	**38**	**1240**	**171**	**417**	**38**	**1158**	**164**	**395**

MMbbl – million barrels

Bcf – billion standard cubic feet

MMboe – million barrels of oil equivalent

* These values are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class.

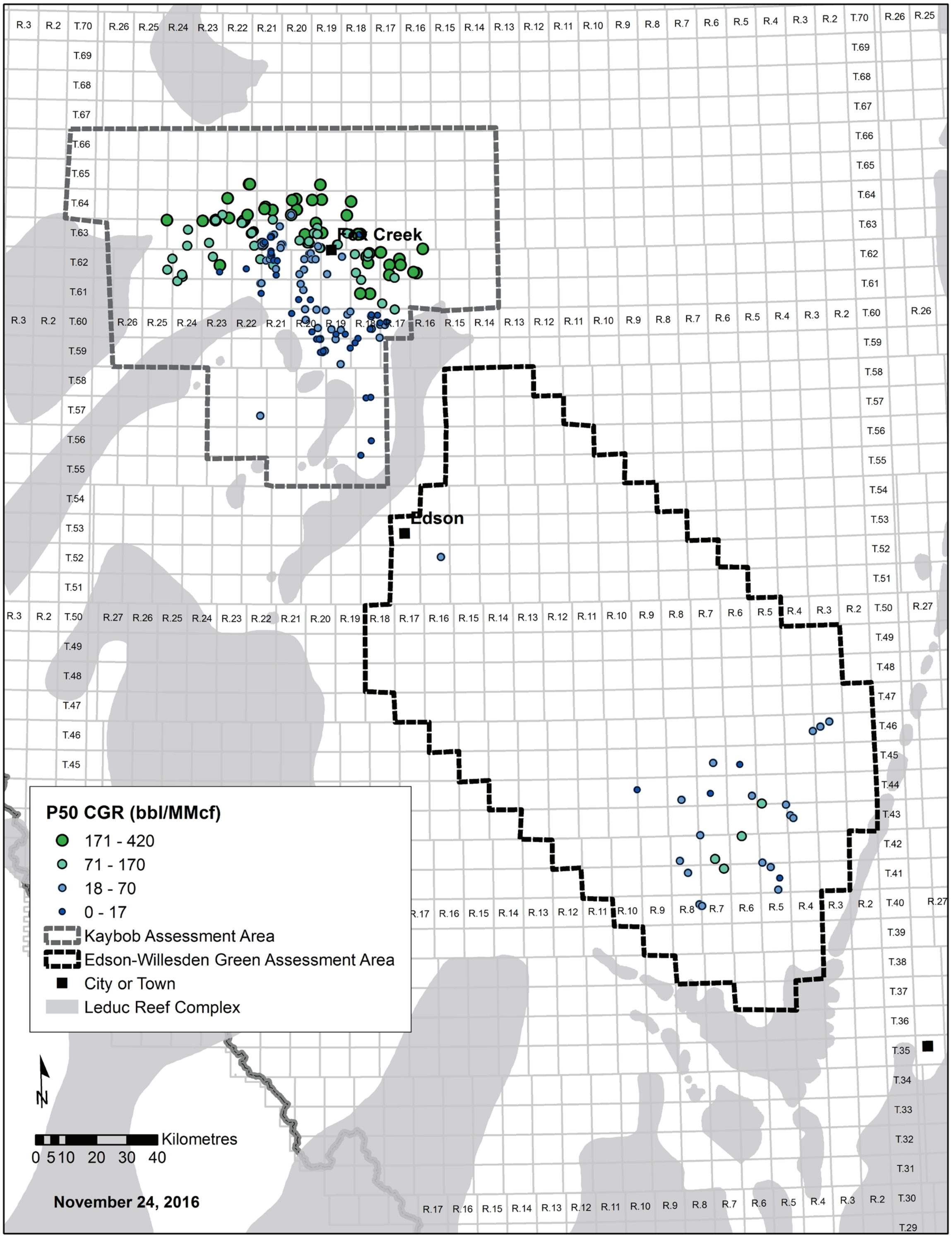

Figure 27. Duvernay P50 CGR_{cum}

the Duvernay. The results of those tests need to be evaluated against the capital expenitures to prove profitability and justify moving into the next stage of development.

Contingent resources in the Duvernay have been classified as “development unclarified” on the basis that additional information, in particular test or pilot data, is being acquired. This may take considerable time. As specified in the COGEH, contingent resources may be assigned a maturity subclass of “development unclarified” if they are still under evaluation or require significant further appraisal to clarify the potential for development and where the contingencies have yet to be fully defined.

7.1 Duvernay Resource Recovery

The three areas of focus within the Duvernay are the Kaybob, Edson-Willesden Green, and Innisfail assessment areas. Currently, development in the Duvernay is at an early stage of long-term development, with several operators active within the assessment areas working to establish the long-term economic viability of the Duvernay. Operators continue to focus operations within the core liquids-rich regions of the Duvernay, which exist within each assessment area.

Contingent resource estimates were determined based on the regional geological parameters, geological prospectivity, expected fluid regions, and the overall results of the Duvernay’s productive capacity evaluated in this report. The recovery technology expected to be used is pad drilling of horizontal multistage fractured wells. In the Duvernay, such wells have proven commerciality across the three assessment areas, but further investigation is required to move into full development. Operators are

Table 5. Total Kaybob reserves effective January 1, 2016*

	Initial				Remaining			
	Oil (MMbbl)	Gas (Bcf)	Condensate (MMbbl)	BOE (MMboe)	Oil (MMbbl)	Gas (Bcf)	Condensate (MMbbl)	BOE (MMboe)
Proved								
Developed Producing	3	352	29	91	3	285	23	73
Developed Nonproducing	0	4	0	1	0	0	0	0
Undeveloped	18	596	116	233	18	596	116	233
Total	**21**	**952**	**145**	**325**	**21**	**881**	**139**	**306**
Proved + Probable								
Developed Producing	4	407	33	105	3	339	27	87
Developed Nonproducing	0	4	0	1	0	0	0	0
Undeveloped	20	633	130	255	20	633	130	255
Total	**24**	**1 044**	**163**	**361**	**23**	**972**	**157**	**342**

MMbbl – million barrels

Bcf – billion standard cubic feet

MMboe – million barrels of oil equivalent

* These values are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class.

Table 6. Total Edson-Willesden Green reserves effective January 1, 2016*

	Initial				Remaining			
	Oil (MMbbl)	Gas (Bcf)	Condensate (MMbbl)	BOE (MMboe)	Oil (MMbbl)	Gas (Bcf)	Condensate (MMbbl)	BOE (MMboe)
Proved								
Developed Producing	1	40	2	9	1	29	1	7
Developed Nonproducing	0	0	0	0	0	0	0	0
Undeveloped	8	138	5	36	8	138	5	36
Total	**9**	**178**	**7**	**45**	**9**	**167**	**6**	**43**
Proved + Probable								
Developed Producing	1	45	2	10	1	35	1	8
Developed Nonproducing	0	0	0	0	0	0	0	0
Undeveloped	9	148	6	39	9	148	6	39
Total	**10**	**193**	**8**	**49**	**10**	**183**	**7**	**47**

MMbbl – million barrels

Bcf – billion standard cubic feet

MMboe – million barrels of oil equivalent

* These values are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class.

Table 7. Total Innisfail reserves effective January 1, 2016*

	Initial				Remaining			
	Oil (MMbbl)	Gas (Bcf)	Condensate (MMbbl)	BOE (MMboe)	Oil (MMbbl)	Gas (Bcf)	Condensate (MMbbl)	BOE (MMboe)
Proved								
Developed Producing	1	1	0	2	1	1	0	1
Developed Nonproducing	0	0	0	0	0	0	0	0
Undeveloped	3	2	0	4	3	2	0	4
Total	**4**	**3**	**0**	**6**	**4**	**3**	**0**	**5**
Proved + Probable								
Developed Producing	2	1	0	2	1	1	0	2
Developed Nonproducing	0	0	0	0	0	0	0	0
Undeveloped	4	3	0	4	4	3	0	4
Total	**6**	**4**	**0**	**6**	**5**	**4**	**0**	**6**

MMbbl – million barrels

Bcf – billion standard cubic feet

MMboe – million barrels of oil equivalent

* These values are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class.

currently conducting completion and spacing pilots throughout the Duvernay to determine favourable interwell spacing and to optimize drilling and completions costs in order to maximize resource recovery. It is believed that this testing will continue throughout the Duvernay until sufficient information is available to suggest long-term economic viability.

As part of the contingent resource evaluation, future potential drilling locations were calculated assuming development over a 15-year period. The development timing for the Duvernay resource recovery may require further appraisal to clarify the potential for development. The economic viability of development within the Duvernay will be assessed as pilot testing results and additional information becomes available.

Development to date has been largely focused within the core liquids-rich regions of the Kaybob assessment area, with additional commercial development taking place across both the Edson-Willesden Green and Innisfail assessment areas. Assuming recent development trends in the Duvernay continue, it is expected that operators will continue with the most common spacing regime of 350–400 metres per well (Figure 18), which equates to a well density of roughly four wells per section. Using typical lateral wellbore lengths of 2000 to 2200 metres (Figure 19), and an eight-well-pad configuration (Figure 20), the equivalent of approximately three sections will be developed per pad. These considerations were used to calculate the number of potential drilling locations that will have contingent resources attributed to them. Contingent resources were assigned within sections with fewer wells and adjacent to existing developed sections.

Contingent resource estimates are not classified as reserves at this time, pending further information from completion and spacing pilots to justify the next phase of development in the Duvernay. These technical issues must be resolved to allow for the widespread commercial application of pad drilling across each assessment area. Uncertainty remains as to the commercial viability to produce any portion of the contingent resources.

Generally, the technical factors that would affect the contingent resources estimates from what is provided in this report includes further decreasing of spacing between well pads and delineation drilling across each assessment area and future technology improvements. Other contingent factors that could be considered include greenhouse gas emissions, water use, and land-use planning. Once contingencies are addressed, the resources may then be reclassified as reserves.

7.2 Contingent Resources Estimation

Contingent resource sections were identified by calculating the number of total sections directly adjacent to any developed sections that are intersected by an existing Duvernay wellbore. The total sections were further refined to remove any sections that exist within boundaries of any major towns or cities or outside the regional Duvernay resource extent. The total number of contingent resource sections was subdivided between the oil, condensate, and gas fluid regions within each assessment area (Figure 5).

It should be noted that since undeveloped reserves were not assigned within the natural gas region of the Kaybob and Edson-Willesden Green assessment areas, those sections were added to the total number of contingent resource sections for those assessment areas. These sections were classified as contingent resources due to their unlikely development within the next five years.

The same 8/3 rule described in Section 5.3 was used to convert the total number of contingent resource sections to future potential contingent well locations. The total contingent resource sections within the natural gas region of the Kaybob and Edson-Willesden Green assessment areas were further adjusted to remove existing wells from the total well count. The total contingent well locations by assessment area are shown in Figure 28.

Across the Duvernay, 3216 potential drilling opportunities were estimated to have contingent resources attributed to them, with 2216 in the Kaybob assessment area, 896 in the Edson-Willesden Green assessment area, and 104 in the Innisfail assessment areas.

The same methods used to assign undeveloped gas, condensate, and oil reserves in Section 5.3.1, Section 5.3.2, and Section 5.3.3, respectively, were used to assign gas, condensate, and oil low estimate contingent resources and best estimate contingent resources within each assessment area.

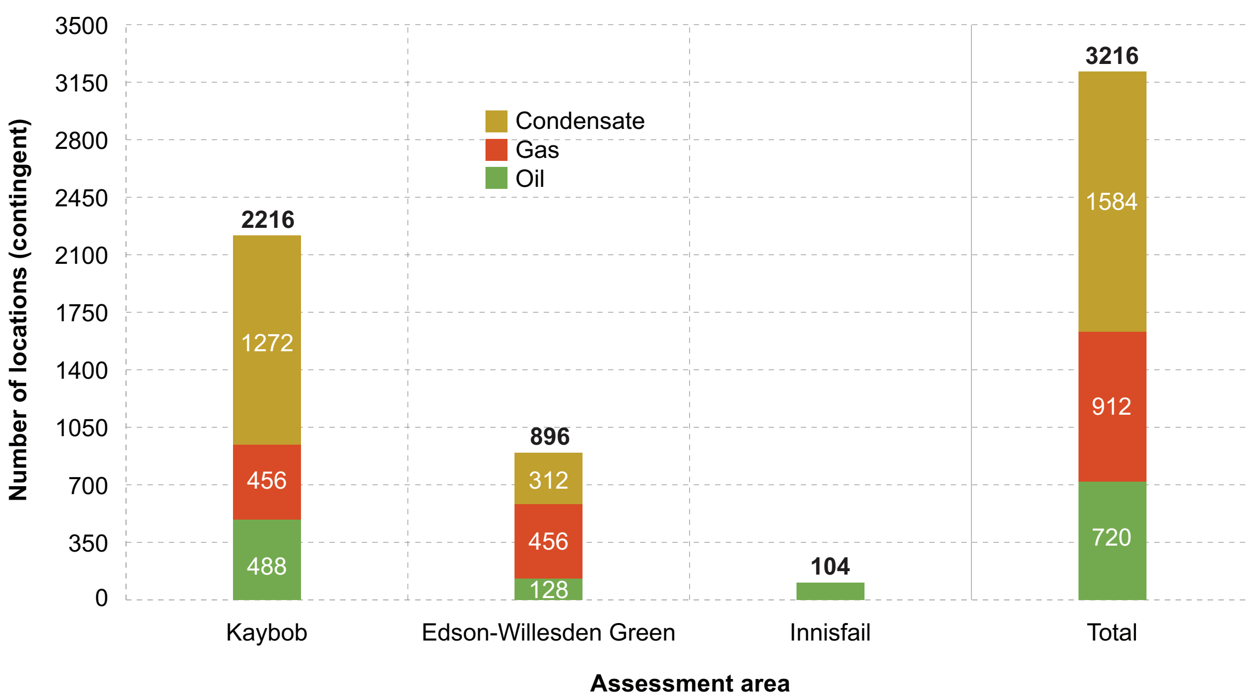

Figure 28. Contingent resource potential drilling locations

7.3 Contingent Resources Results

Duvernay contingent resources were estimated for oil, gas, and condensate by assessment area. Total contingent resources were determined by summing the results from each assessment area in accordance with the aggregation principles outlined in Section 2.8 of the COGEH.

In such cases, the chance of commerciality may be difficult to assess with any confidence. As such, the contingent resource estimates were not further adjusted for commercial risks as to the chance of development.

7.3.1 Total Duvernay Contingent Resources

Low estimate contingent resources are 1540 MMboe and best estimate contingent resources are 1676 MMboe. The total potentially recoverable contingent resources are provided in Table 8.

Within the COGEH resource classification system, reserves are separated from contingent resources by the level of risk of attaining commercial production. The estimates of contingent resources are estimates only and there is no assurance that the estimated contingent resources will be recovered. Although probabilistic techniques were used to account for the large range of technical uncertainty associated with these estimates, uncertainty remains associated with geological and reservoir engineering constraints, recovery efficiencies, and additional economic factors. There is also uncertainty that it will be commercially viable to produce any part of the contingent resources. Contingent resources may be assessed periodically to determine whether the contingent resources should be reclassified as reserves in accordance with Section 2.5.7 of the COGEH.

7.3.2 Contingent Resource by Assessment Area

Duvernay contingent resources were estimated for oil, gas, and condensate within the Kaybob, Edson-Willesden Green, and Innisfail assessment areas. The potentially recoverable low estimate and best estimate contingent resources by assessment area are provided in Table 8.

Table 8. Contingent resources by assessment area, effective January 1, 2016*

	Oil (MMbbl)	Gas (Bcf)	Condensate (MMbbl)	BOE (MMboe)
Kaybob				
Low estimate	99	3 772	541	1 269
Best estimate	110	4 000	608	1 384
Edson-Willesden Green				
Low estimate	26	1 204	21	241
Best estimate	29	1 284	22	265
Innisfail				
Low estimate	21	16	0	24
Best estimate	23	18	0	26
Total Duvernay				
Low estimate	**145**	**4 992**	**562**	**1 540**
Best estimate	**162**	**5 301**	**630**	**1 676**

* Low estimate and best estimate contingent resources were not further adjusted for risk.

8 Prospective Resources

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development (SPEE, 2007). This differs from the initially-in-place hydrocarbon estimates published in ERCB (2012), which provides regional resource endowment estimates but does not account for future development projects.

The estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum is referred to as the "chance of discovery." The estimated probability that, once discovered, a known accumulation will be commercially developed is referred to as the "chance of development." The chance of commerciality is the product of the chance of discovery and the chance of development (SPEE, 2007).

Based on the published resource estimates for the Duvernay (Rokosh et al., 2012) and the regional geological overview and summary of the Duvernay's productive capacity contained in this report, the AER has subclassified the best estimate prospective resources associated with the Duvernay by maturity status "prospect," which is defined in the COGEH as a potential accumulation that is sufficiently well defined to represent a viable drilling target.

8.1 Prospective Resources Estimation

Prospective resources are assigned on the basis of technology under development and are an extension of the contingent resources in the Duvernay (Section 7.3). With a general spacing of 350 – 400 m per well (Figure 18) and horizontal wellbore lengths of about 2200 m (Figure 19), an eight-well-pad configuration (Figure 20) could be realized over the equivalent of approximately three sections per pad.

These considerations were used to calculate the number of potential drilling locations that will have prospective resources attributed to them. Prospective resource sections were identified by calculating the number of total sections within two miles of any sections classified as containing contingent resources. The total sections were further refined to remove any sections that exist within boundaries of any major towns or cities or outside the regional Duvernay resource extent. The total number of prospective resource sections was subdivided between the oil, condensate, and gas fluid regions (Figure 5) within each assessment area.

The recovery technology expected to be used is pad drilling of multistage hydraulically fractured wells. The same 8/3 rule described in Section 5.3 was used to convert the total number of prospective resource sections to future potential prospective well pad locations. The total prospective well locations by assessment area are shown in Figure 29.

Across the Duvernay, 4536 potential drilling opportunities were estimated to have prospective resources attributed to them, with 1944 in the Kaybob assessment area, 2152 in the Edson-Willesden Green

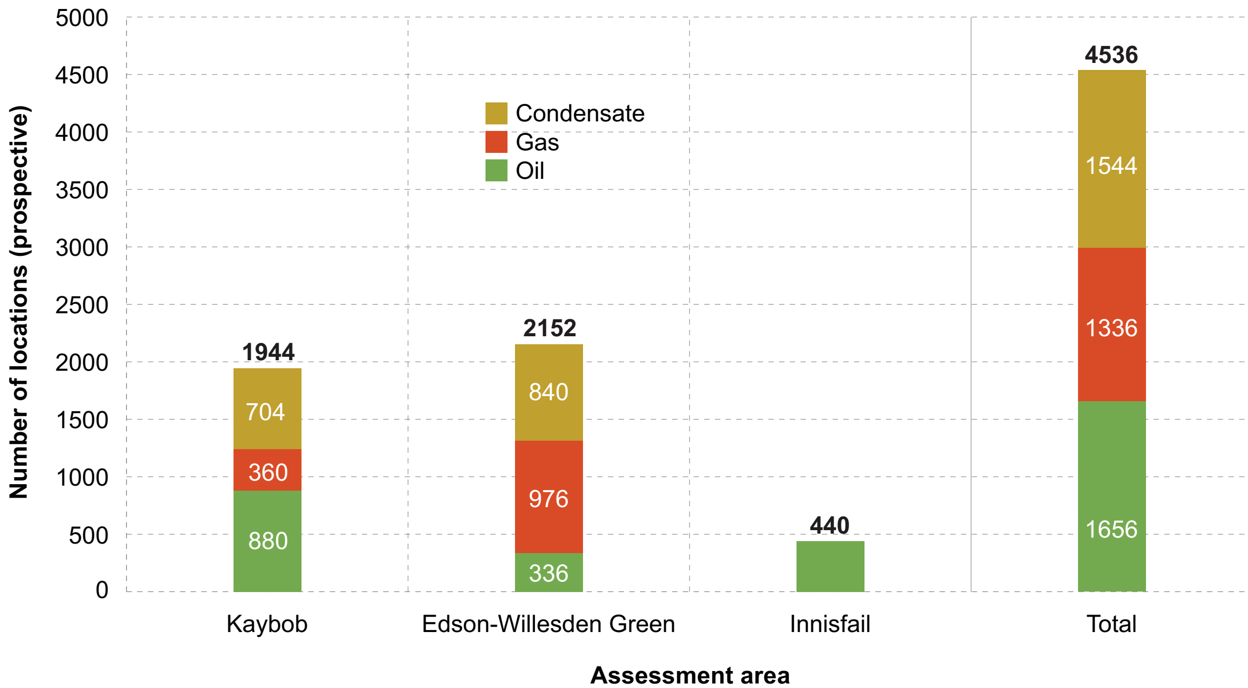

Figure 29. Prospective resource potential drilling locations

assessment area, and 440 in the Innisfail assessment area. As part of the prospective resource evaluation, future potential drilling locations were calculated assuming development over a 15- to 30-year period.

The same methodologies used to assign undeveloped gas, condensate, and oil reserves in Section 5.3.1, Section 5.3.2, and Section 5.3.3, respectively, were used to assign gas, condensate, and oil best estimate prospective resources within each assessment area. Since a full economic evaluation was not undertaken, the chance of commerciality for prospective resources in the Duvernay was estimated at 50% for each assessment area.

There is an opportunity to convert prospective resources into contingent resources and eventually into reserves as new technology is developed and further cost savings are realized.

Generally, the technical factors that would affect the prospective resource estimates from what is provided in this report includes further decreasing the spacing between pad wells and delineation drilling across each assessment area and future technology improvements. The amount of this resource that can be economically recovered is dependent on drilling and completions optimization, cost reductions, expected liquids yields, processing capacity, facility design, additional transport, commodity pricing, and other social, environmental, and regulatory constraints.

8.2 Prospective Resources Results

Prospective resources associated with the Duvernay were estimated for oil, gas, and condensate by assessment area, and are subclassified as maturity status "prospect." A commercial risk factor of 50% was applied to the EUR estimates to derive a risked prospective resources best estimate given the uncertainty that it will be commercially viable to produce any portion of the prospective resources associated with the Duvernay. Total regional risked prospective resources were determined by summing the results from each assessment area.

8.2.1 Total Duvernay Prospective Resources

Best estimate risked prospective resources are 864 MMboe. The total potentially recoverable risked best estimate prospective resources are provided in Table 9.

The estimates of prospective resources are estimates only and there is no assurance that the estimated prospective resources will be recovered. There is also uncertainty that it will be commercially viable in the future to produce any part of the prospective resources.

8.2.2 Prospective Resources by Assessment Area

Duvernay prospective resources were estimated for oil, gas, and condensate within the Kaybob, Edson-Willesden Green, and Innisfail assessment areas. The potentially recoverable risked best estimate prospective resources by assessment area are provided in Table 9.

9 Future Work

The reserves and resources estimates provided in this report are based on new probabilistic techniques, and will be changed as new information becomes available. Future work will include

- a comprehensive geological assessment of the Duvernay Innisfail play,
- direct estimations of time to end of linear flow as an input for probabilistic declines,
- full probabilistic declines as inputs for the time-series simulation, and
- revised methods for determining the chance of commerciality for contingent and prospective resources.

Table 9. Prospective resources (best estimate) by assessment area, effective January 1, 2016*

	Oil (MMbbl)	Gas (Bcf)	Condensate (MMbbl)	BOE (MMboe)
Kaybob	99	1 310	168	486
Edson-Willesden Green	38	1 527	30	322
Innisfail	50	37	0	56
Total Duvernay	**186**	**2 873**	**198**	**864**

* A commercial risk factor of 50% was applied.

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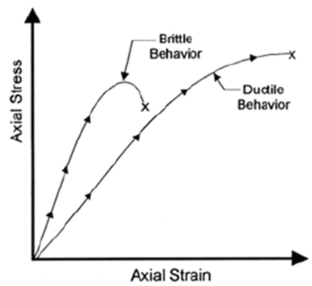
Appendix 1 Reserves Glossary

brittleness	A material is brittle if, when subjected to stress, it breaks or fractures without significant deformation or strain. When developing oil and gas using hydraulic fracturing, brittle rock is desirable because it fractures easier. 
brittleness index	A measurement of how brittle a rock is, expressed as a percentage. Generally, there are three methods of calculating the brittleness index of a rock: using geomechanical properties of the rock (Poisson's ratio, Young's modulus, Lamé parameters of incompressibility), by calculating the proportion of brittle minerals to nonbrittle minerals, or using a strength parameter to derive a brittleness index.
carbonate	Carbonate rocks are a class of sedimentary rock whose chief mineral constituents (95% or more) are calcite and aragonite (both CaCo3) and dolomite $[CaMg(CO_3)_2]$. Limestone, dolostone or dolomite, and chalk are carbonate rocks. Although carbonate rocks can be clastic in origin, they are more commonly formed through processes of precipitation or the activity of organisms such as coral and algae. Carbonates form in shallow and deep marine settings, evaporitic basins, lakes and windy deserts.
clastic	Clastic rocks are silica-based, noncarbonaceous sediments that have been broken from pre-existing rocks, transported elsewhere, and redeposited before reforming another rock.Examples of common sedimentary rocks include conglomerate, sandstone, siltstone and shale.
conventional resources	Conventional resources are those that have the necessary rock permeability and fluid viscosity to be commercially productive without the use of stimulation technology. These resources are buoyancy-driven deposits that accumulate in structural or stratigraphic traps.

core	Core is rock recovered during the processes of drilling a well. A core bit is used to cut away a cylinder of rock from the formation and pull the cylinder with core sample intact back up to surface. Once at surface, various sampling and testing can be done to better understand the rock formation.
core analysis	Core analysis is the laboratory study of a sample of geological formation, usually reservoir rock, collected during or after drilling a well. Economic and efficient oil and gas production is highly dependent on understanding key properties of reservoir rock, such as porosity, permeability, and wettability.
deep basin	The prolific Deep Basin parallels the western edge or structural foredeep of the Western Canada Sedimentary Basin and forms a regionally extensive area of hydrocarbon-saturated, abnormally pressured, thermally mature rocks characterized by multiple, stacked, lower permeability gas and oil reservoirs, characterized by little to no water production.
isopach map	A means of displaying contoured points of equal thickness.
limestone	Limestone is a carbonate sedimentary rock predominantly composed of calcite of organic, chemical, or detrital origin. Minor amounts of dolomite, chert, and clay are common in limestones. Chalk is a form of fine-grained limestone.
lithostratigraphy	The branch of stratigraphy that classifies rock layers based on the observiable properties of the layers and their relative positions to each other. Lithostratigraphic units are the basic units of geological mapping. The conventional hierarchy of formal lithostratigraphic terms is as follows: group (two or more formations), formation (primary unit of lithostratigraphy), member (named lithological subdivision of a formation), and bed (named distinctive layer in a member or formation).
overpressure	Subsurface pressure that is abnormally high, exceeding hydrostatic pressure at a given depth. Drilling into overpressured strata can be hazardous because overpressured fluids escape rapidly, so careful preparation is made in areas of known overpressure.
permeability	Permeability is defined as the ability, or measurement of a rock's ability, to transmit fluids, typically measured in darcies or millidarcies.
play	A geological play can be defined as a set of known or postulated oil or gas accumulations (pools and deposits) within a petroleum system sharing similar geological, geographic, and temporal properties, such as source rock, migration pathways, timing, trapping mechanism, and hydrocarbon type.

Poisson's ratio (v)	An elastic constant that is a measure of the compressibility of material perpendicular to applied stress, or the ratio of latitudinal to longitudinal strain. Poisson's ratio can be expressed in terms of properties that can be measured in the field, including velocities of P-waves (VP) and S-waves (VS). The equation for Poisson's ratio is shown below: $v = \frac{1}{2}({V_P}^2 - 2{V_S}^2) \div ({V_P}^2 - {V_S}^2)$
pool	The *Oil and Gas Conservation Act* defines a pool as a natural underground reservoir containing or appearing to contain an accumulation of oil or gas, or both, separated or appearing to be separated from any other such accumulation.
porosity	Total porosity is defined as the percentage of pore volume or void space, or the volume within a reservoir that can contain fluids, but does not necessarily contribute to flow. Effective porosity is defined as the interconnected pore volume that contributes to fluid flow in a reservoir. The effective porosity in a reservoir is the result of subtracting bound fluids (on clays and shales) and isolated pores from the total porosity. Therefore, effective porosity is typically less than total porosity.
porosity thickness	Porosity thickness is the calculation of average porosity (PHI) multiplied by thickness (H), PHI × H, and is pore volume per unit area. Porosity thickness can be the multiplication of PHI with net pay, gross pay, or any other user-defined thickness.
probabilistic values (P10, P50, P90)	The values P10, P50, and P90 represent confidence levels for an estimate. P50 represents the middle estimate. When looking at a range of possible values, it's the one in the middle (the median). P10 is the point where 10% of the values are greater (a high estimate). P90 is the point where 90% of the values are greater (a low estimate).
reservoir	A reservoir is a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. Sedimentary rocks are the most common reservoir rocks because they have more porosity than more igneous and metamorphic rocks and form under temperature conditions at which hydrocarbons can be preserved. A reservoir is a critical component of a complete petroleum system.

shale	As a general guide, the AER uses the criteria published in *Bulletin 2010-28* for defining mudstone/shale: • A laminated rock with >67 per cent clay-sized minerals, often with fissility. • A blocky or massive fine grained sedimentary rock in which the proportion of clay is approximately equal to or greater than silt-sized particles. • A fine grained, low permeability clastic, carbonate, or mixed-lithology rock of which the exact composition is unknown; however, on a geophysical log, the response of the production interval is uniformly shaly.
shale gas	Shale gas is trapped in the pores and fractures in low permeability rocks and by adsorption on kerogen and possibly clay particles. It is released when a pressure differential develops. Extensive hydraulic fracturing is required to facilitate production.
source rock	A source rock is a rock rich in organic matter which, if heated sufficiently, will generate oil or gas. Rocks of marine origin tend to be oil prone, whereas terrestrial source rocks (such as coal) tend to be gas prone. Due to advancements in technology, source rocks may also be targeted as reservoir rocks through the use of horizontal drilling and multistage fracturing.
stratigraphic cross-section	A diagram of a vertical section that uses a stratigraphic horizon as a datum. It is useful for correlating tops and determining depositional relationships.
structure map	A structure map is a type of subsurface map where contours represent the elevation of a particular formation, reservoir, or geological marker in space such that folds, faults, and other geological structures are clearly displayed.
tight oil or gas	Tight oil or gas is predominantly trapped in the pores and fractures in low permeability rocks. Extensive stimulation is required to facilitate production. Trapping mechanisms may be due to buoyancy/seal in some tight gas resources, or relative permeability effects in basin-centred gas systems.

tight hybrid	Tight hybrid resources are low permeability rocks that cannot be easily divided into "conventional" or "unconventional" resources by simplified factors such as fluid viscosity, permeability, or recovery process. Areas of mature conventional resources may also contain areas of low permeability that could not be exploited by traditional conventional means and are now being exploited using unconventional type methods, including horizontal wells and multistage hydraulic fracturing. This definition applies to halo-type deposits where the quality of the reservoir decreases with increasing distance from the conventional core, and to mixed-lithology reservoirs containing both conventional and unconventional type deposits.
total organic carbon	Total organic carbon is the concentration of organic material in source rocks as represented by the weight per cent of organic carbon. A value of approximately 0.5% total organic carbon by weight per cent is considered the minimum for an effective source rock, although values of 2% are considered the minimum for shale gas reservoirs. Total organic carbon is measured from 1 g samples of pulverized rock that are combusted and converted to CO or CO_2.
unconventional resources	Unconventional resources are those that require alteration of the rock permeability or fluid viscosity to be commercially productive. These resources are not generally buoyancy-driven deposits and often occur as regionally extensive accumulations independent of structural or stratigraphic traps.
well logs and logging	Well logging is the process of acquiring in situ formation information from either the open or cased well hole using various electrical, acoustic and radioactive tools. Well logs are the result of well logging and can be presented in the digital or raster form.
Young's modulus (E)	An elastic constant that is the ratio of longitudinal stress to longitudinal strain. $E = \frac{longitudinal\ stress}{longitudinal\ strain}$

Appendix 2 Geological Maps

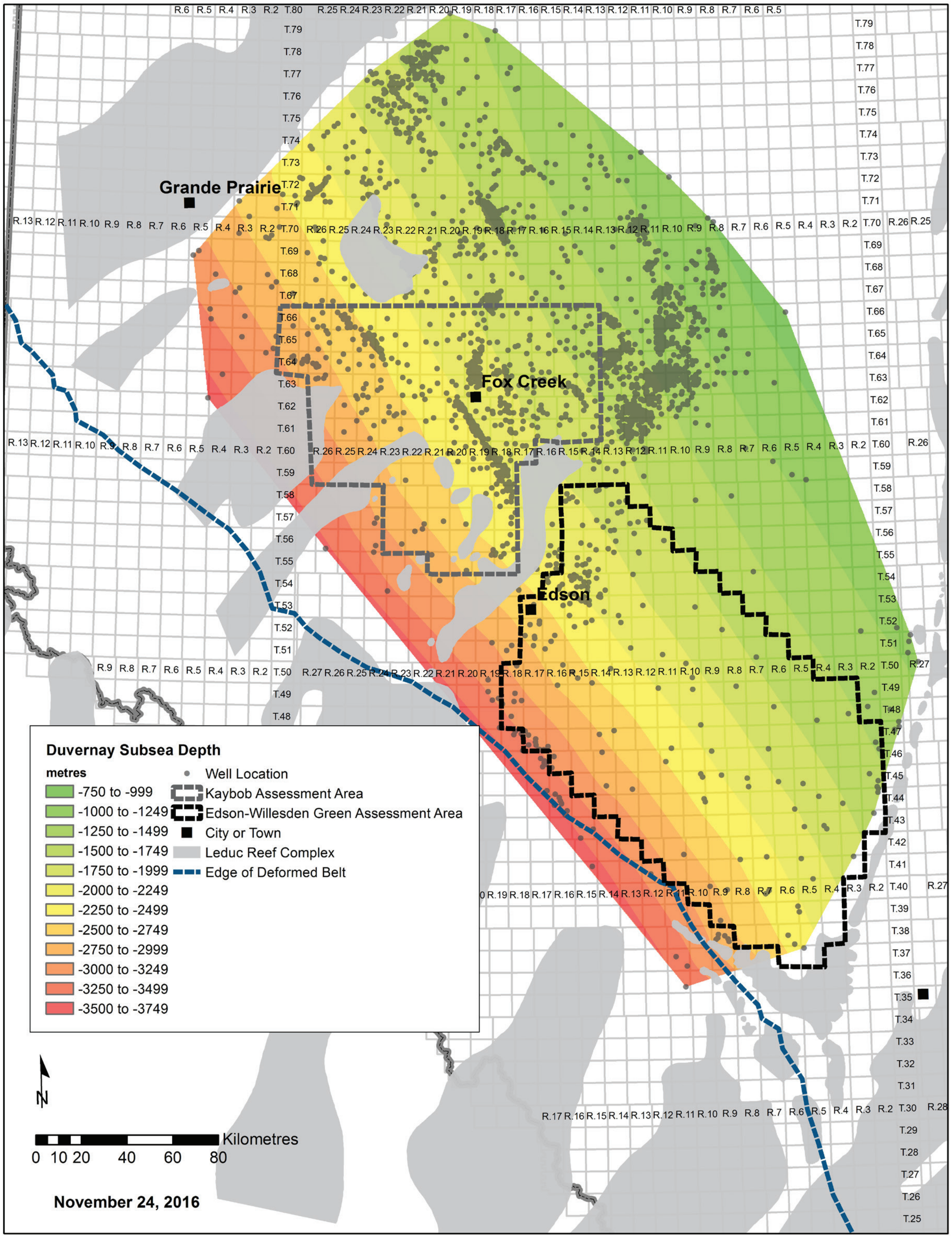


Figure 30. Duvernay structure map

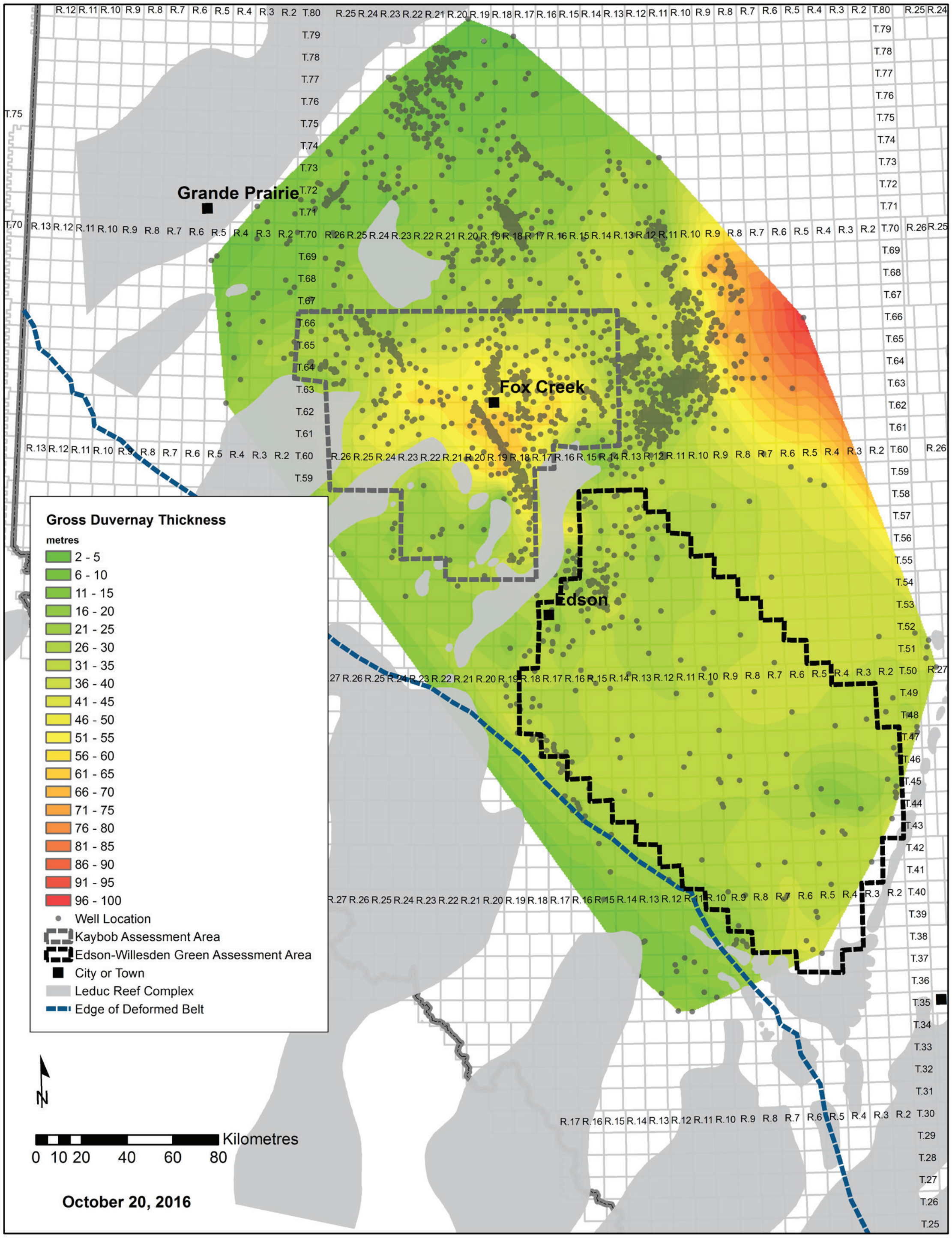


Figure 31. Duvernay gross isopach map

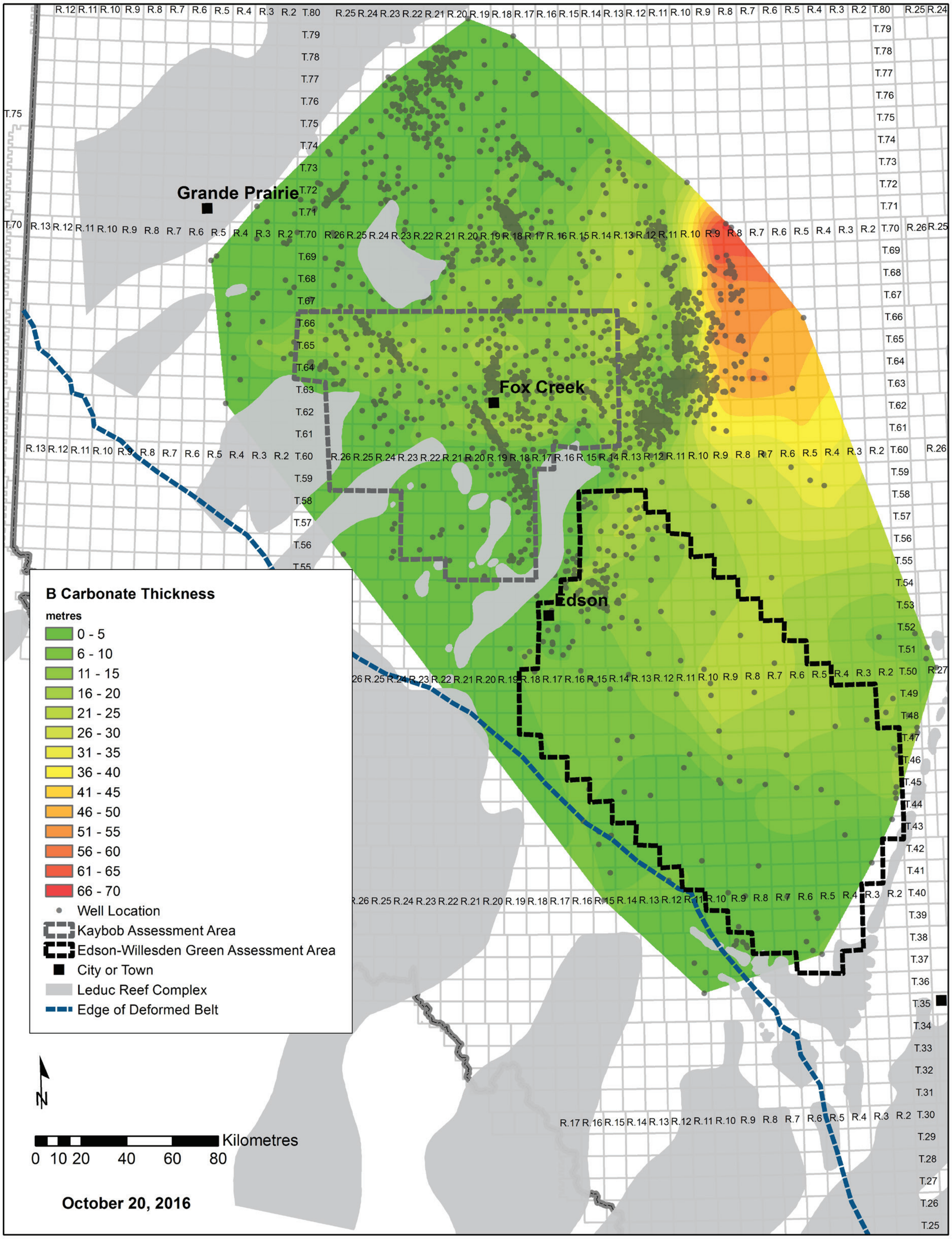


Figure 32. Duvernay B carbonate isopach map

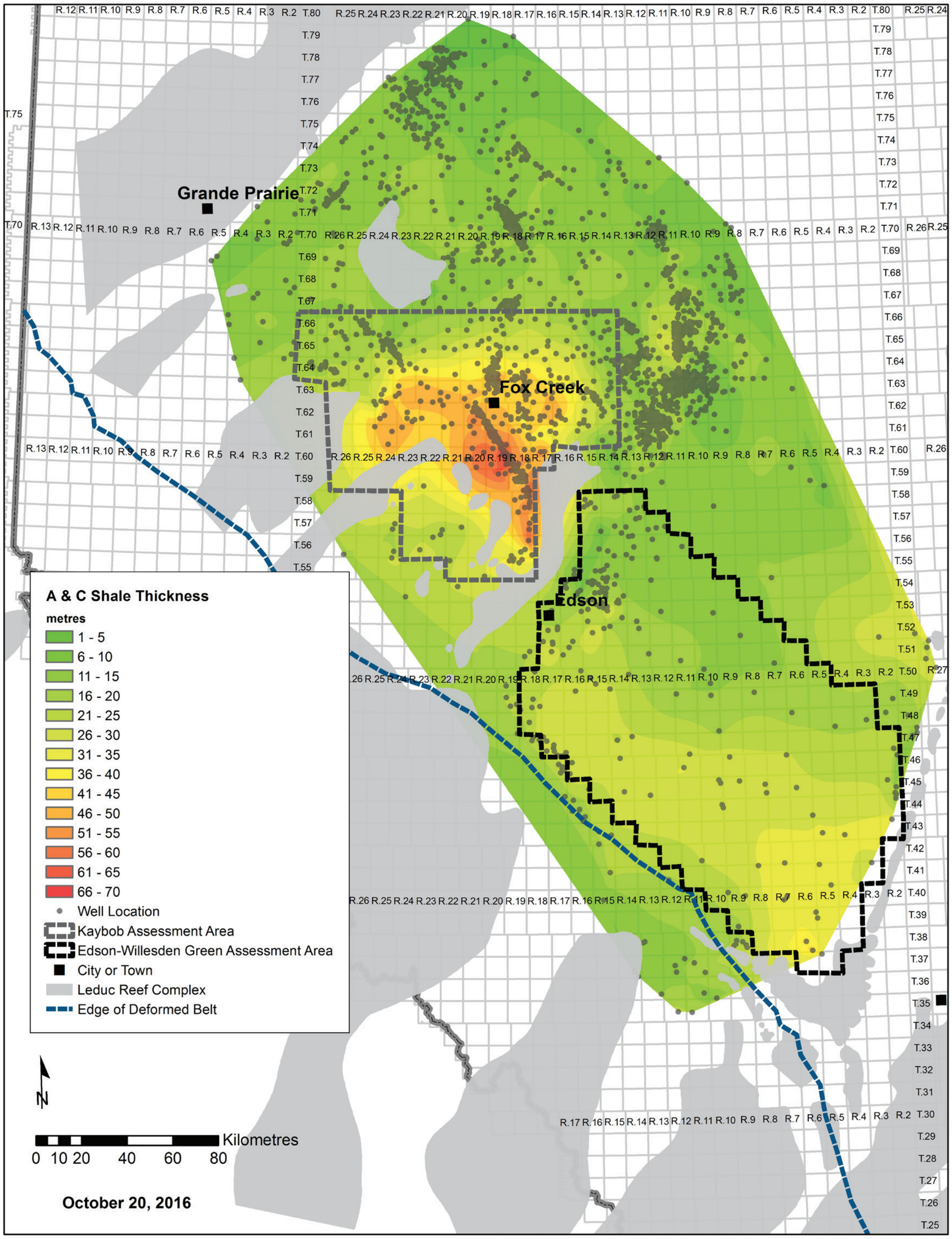


Figure 33. Duvernay A & C shales isopach map

Appendix 3 Geological Methods

Porosity

Porosity was calculated for 593 wells within the Fox Creek play from bulk density curves. Porosity was only calculated for the A and C shale members, using the following equation and input variables:

$$porosity = \frac{(matrix\ density - bulk\ density)}{(matrix\ density - fluid\ density)},$$

where *matrix density* is the density of shale corrected for kerogen content (2670 kg/m^3); *bulk density* is the digital, normalized bulk density curve (kg/m^3); and *fluid density* is the density of water (1000 kg/m^3). See Figure 34 and Figure 35.

Porosity Thickness (PhiH)

Porosity thickness (PhiH) was calculated for 703 wells within the Fox Creek play from the resulting calculated porosity curves. Porosity thickness was only calculated for the A and C shale members, using the following equation and input variables:

$$PhiH = porosity \times thickness,$$

where *porosity* is the calculated porosity curve and *thickness* is the thickness of A and C shale members (m). A porosity cutoff was not used when calculating PhiH. See Figure 36 and Figure 37.

Brittleness Index

Brittleness index was calculated for 55 wells within the Fox Creek play. Brittleness index was only calculated for the A and C shale members, using the following equation and input variables:

$$brittleness\ index = \left\{100\left[\frac{(Young's - min_y)}{(max_y - min_y)}\right] + 100\left[\frac{(Poisson's - min_p)}{(max_p - min_p)}\right]\right\}^2,$$

where *Young's* is Young's modulus curve (GPa), min_y is the minimum Young's modulus value (18.14 GPa), max_y is the maximum Young's modulus value (73.71 GPa), *Poisson's* is Poisson's ratio curve (unitless), min_p is the minimum Poisson's Ratio value (0.01), and max_p is the maximum Poisson's Ratio value (0.37). See Figure 38 and Figure 39.

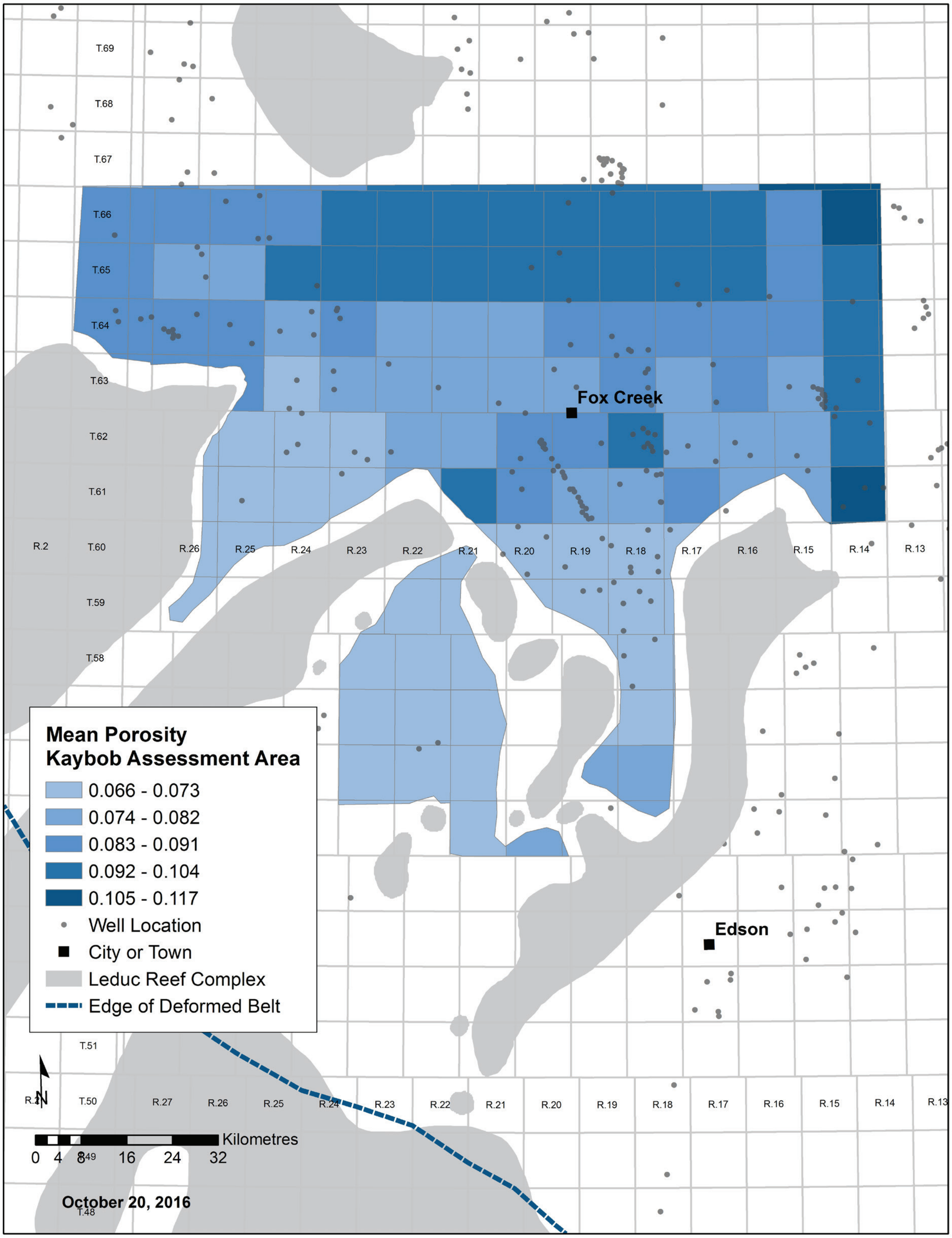


Figure 34. Mean porosity, Kaybob assessment area

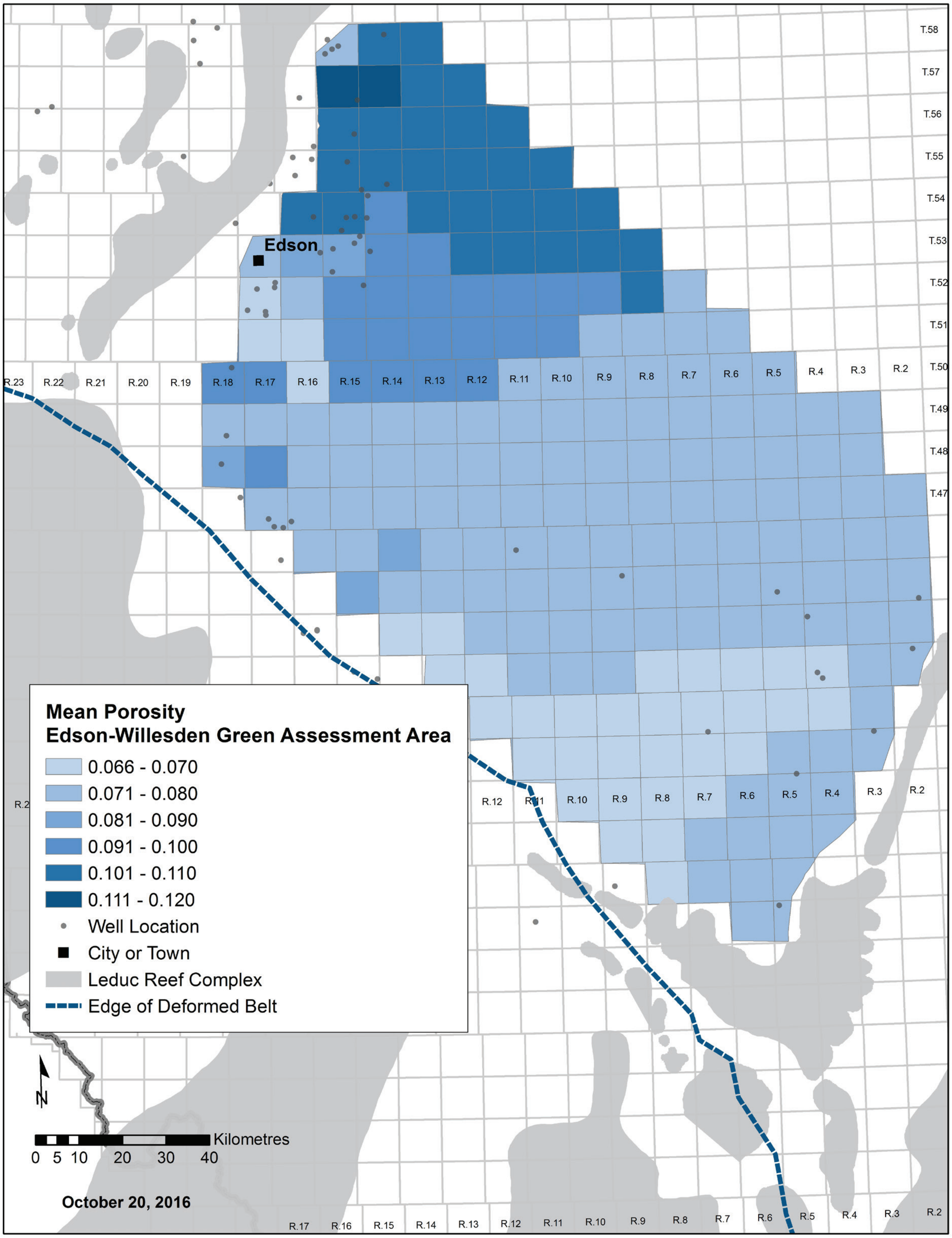


Figure 35. Mean porosity, Edson-Willesden Green assessment area

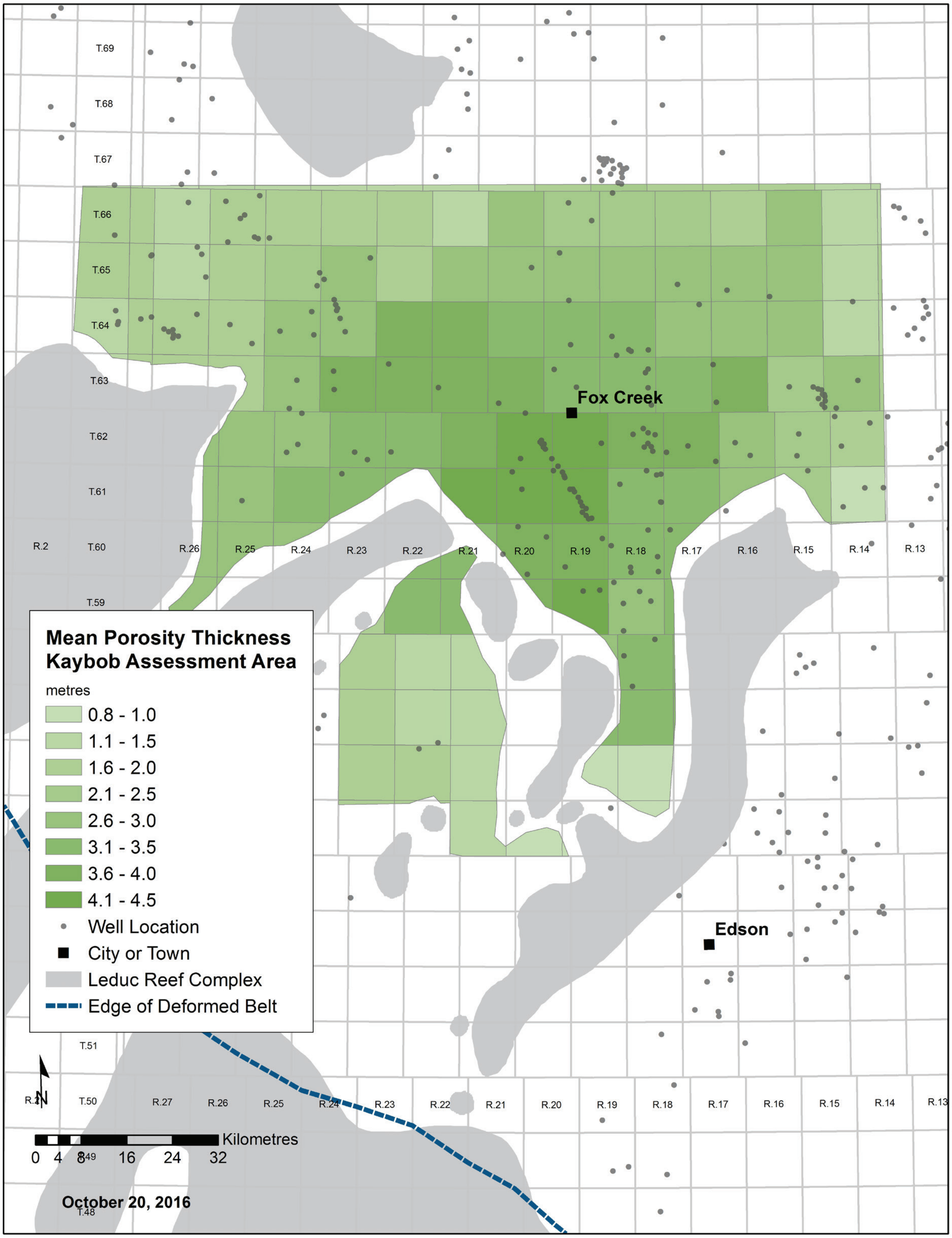


Figure 36. Mean porosity thickness, Kaybob assessment area

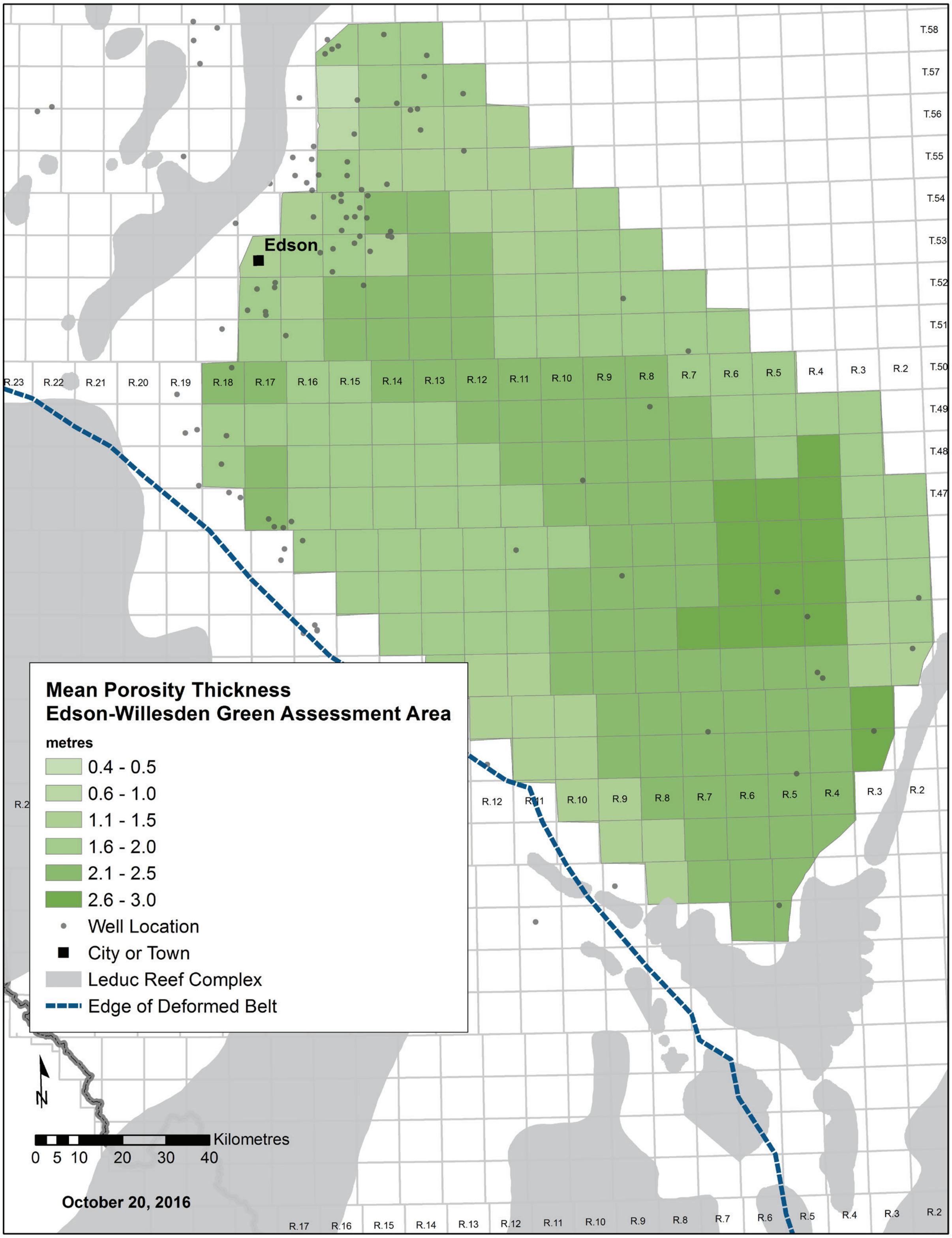


Figure 37. Mean porosity thickness, Edson-Willesden Green assessment area

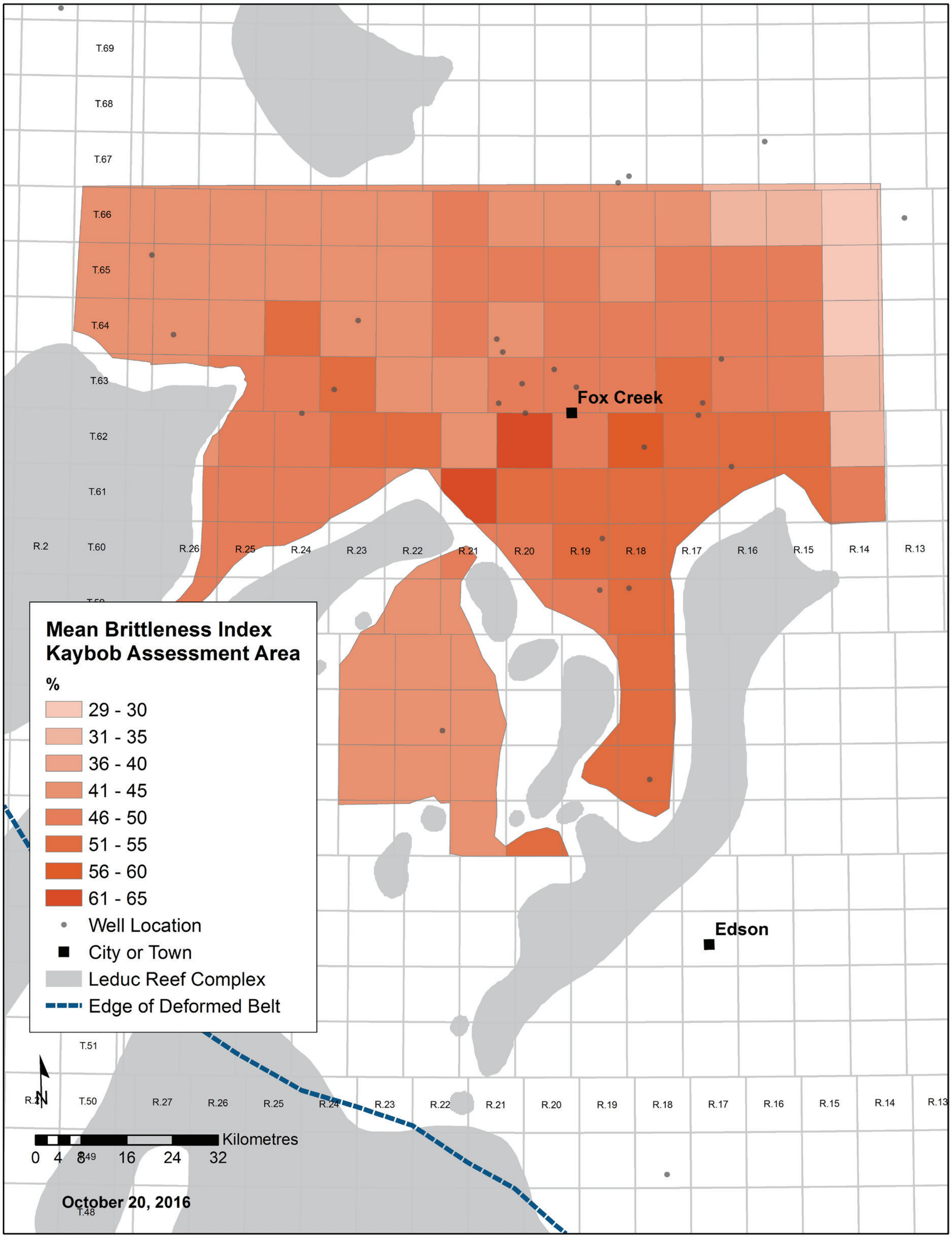


Figure 38. Mean brittleness index, Kaybob assessment area

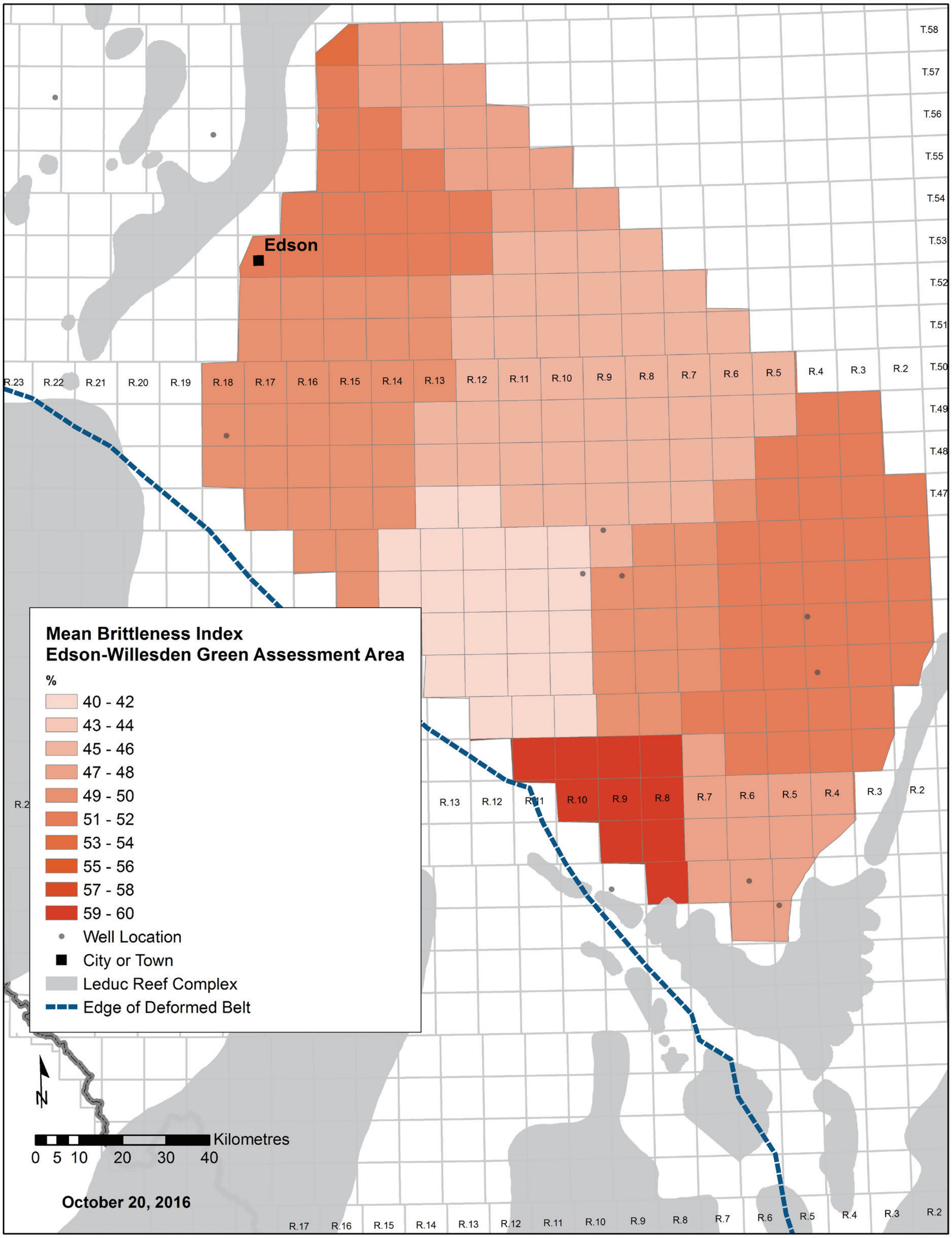


Figure 39. Mean brittleness index, Edson-Willesden Green assessment area

Total Organic Carbon

Total organic carbon (TOC) was calculated for 241 wells within the Fox Creek play from sonic and resistivity curves. Total organic carbon was only calculated for the A and C shale members, using Passey's et al equation (1990) and the following input variables:

$$total\,organic\,carbon = \left[\log\left(\frac{ResD}{RBase}\right) + 0.02(DT - DTBase)\right] \times 10^{(0.297 - 0.1688 \times LOM)} \ ,$$

where *ResD* is the deep resistivity curve (ohm-m); *RBase* is the baseline resistivity of a nonorganic shale (ohm·m), which is 7 ohm·m; *DT* is the sonic curve (usec/m); *DTBase* is the baseline sonic value of a nonorganic shale (ohm·m), which is 220 usec/m; and LOM is the level of maturity, which is 11 (oil region), 11.5 (condensate region), and 12 (gas region), determined by calibrating calculated curves to core analysis data. See Figure 40 and Figure 41.

T_{max}

Pyrolysis is the decomposition of organic matter by heating in the absence of oxygen. Organic geochemists use pyrolysis analysis to measure the richness and maturity of potential source rocks. Pyrolysis can also be used to infer the kerogen types within a sample.

Pyrolysis is performed by starting with a small sample of crushed rock material. The sample is heated in four stages, initially to 300°C for the first stage, then ultimately to 640°C. The hydrocarbons that are released are measured. Four peaks exist in the results, as shown in Figure 42.

On heating, the first peak encountered is S1, which represents the existing hydrocarbons in the sample being released. During the second heating stage, the S2 peak is encountered. It represents the milligrams of residual hydrocarbons in one gram of rock, which corresponds to the potential amount of hydrocarbon that the rock can still produce if thermal maturation continues. The temperature at which S2 releases its maximum rate of hydrocarbon generation is called T_{max}, and it represents the amount of heat necessary to create the cracking of kerogen and releasing of heavy hydrocarbons. The third heating stage provides results for the S3 peak, which corresponds to the CO_2 that is generated from the thermal cracking of kerogen during pyrolysis. The final peak represents S4, which is the residual organic carbon.

The T_{max} for a sample can be used to infer expected fluid type encountered at the equivalent location in the reservoir. The temperature windows used to estimate the fluid types are as follows:

- 425°C to 450°C for oil
- 450°C to 470°C for condensate
- 470°C to 500°C for gas

The T_{max} data for 35 wells is shown with the temperature windows in Figure 43.

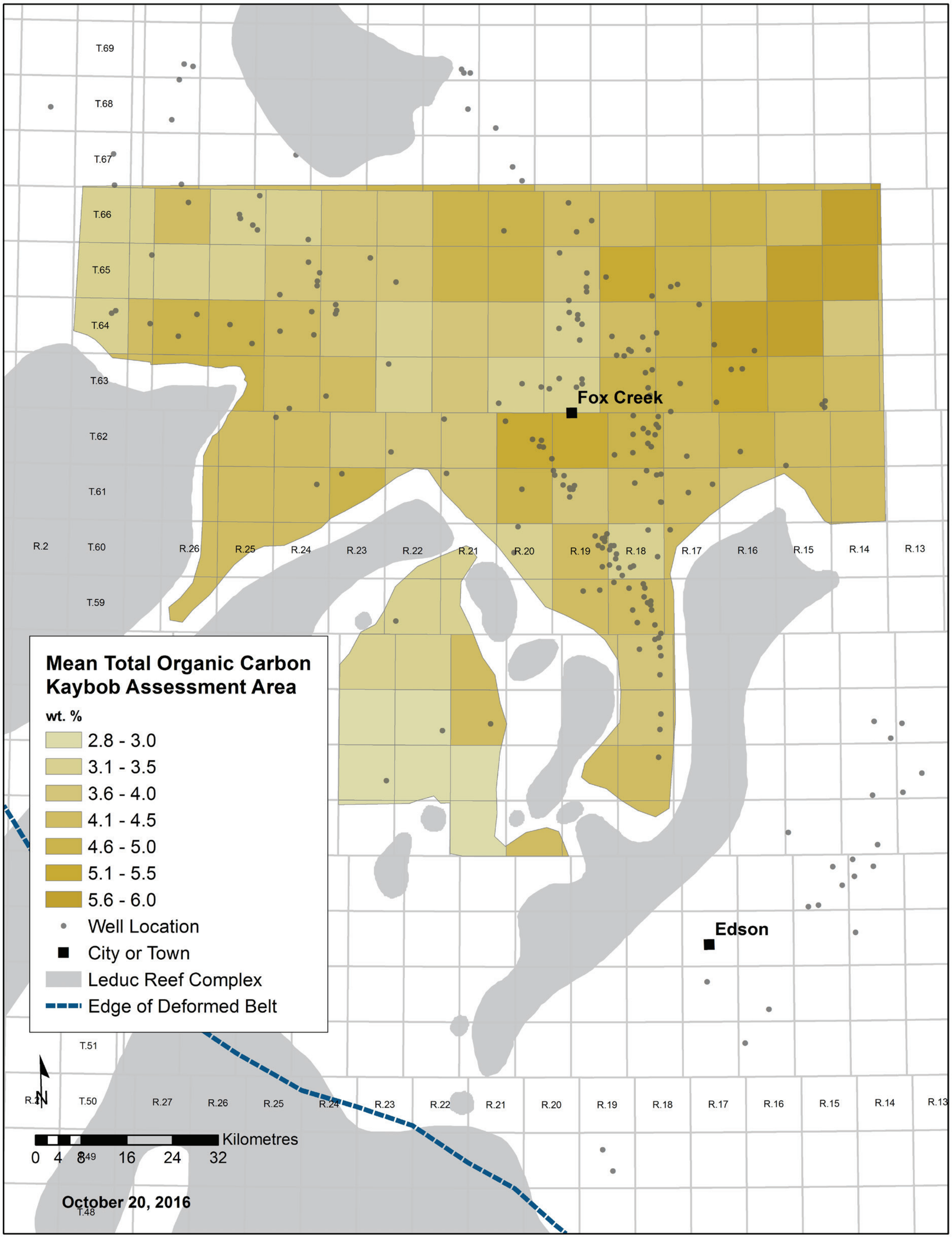


Figure 40. Mean total organic carbon, Kaybob assessment area

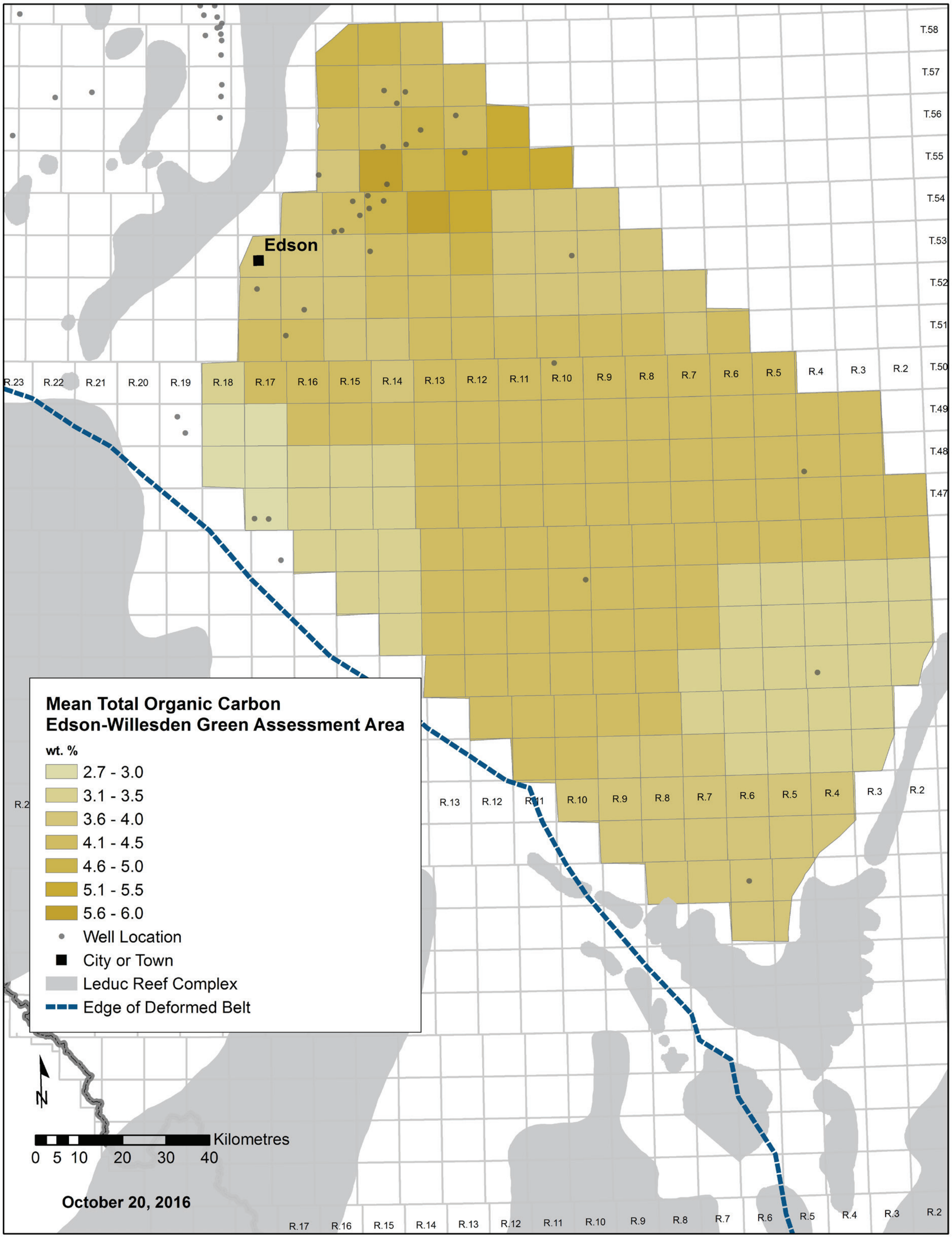


Figure 41. Mean total organic carbon, Edson-Willesden Green assessment area

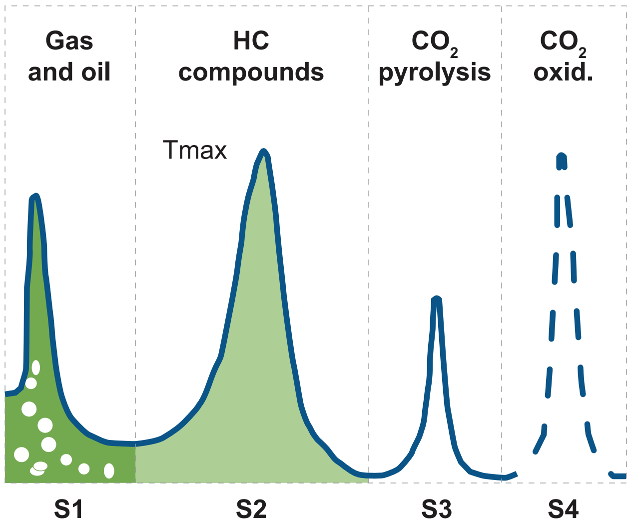


Figure 42. Hydrocarbon peaks measured from pyrolysis (from McCarthy et al., 2009)

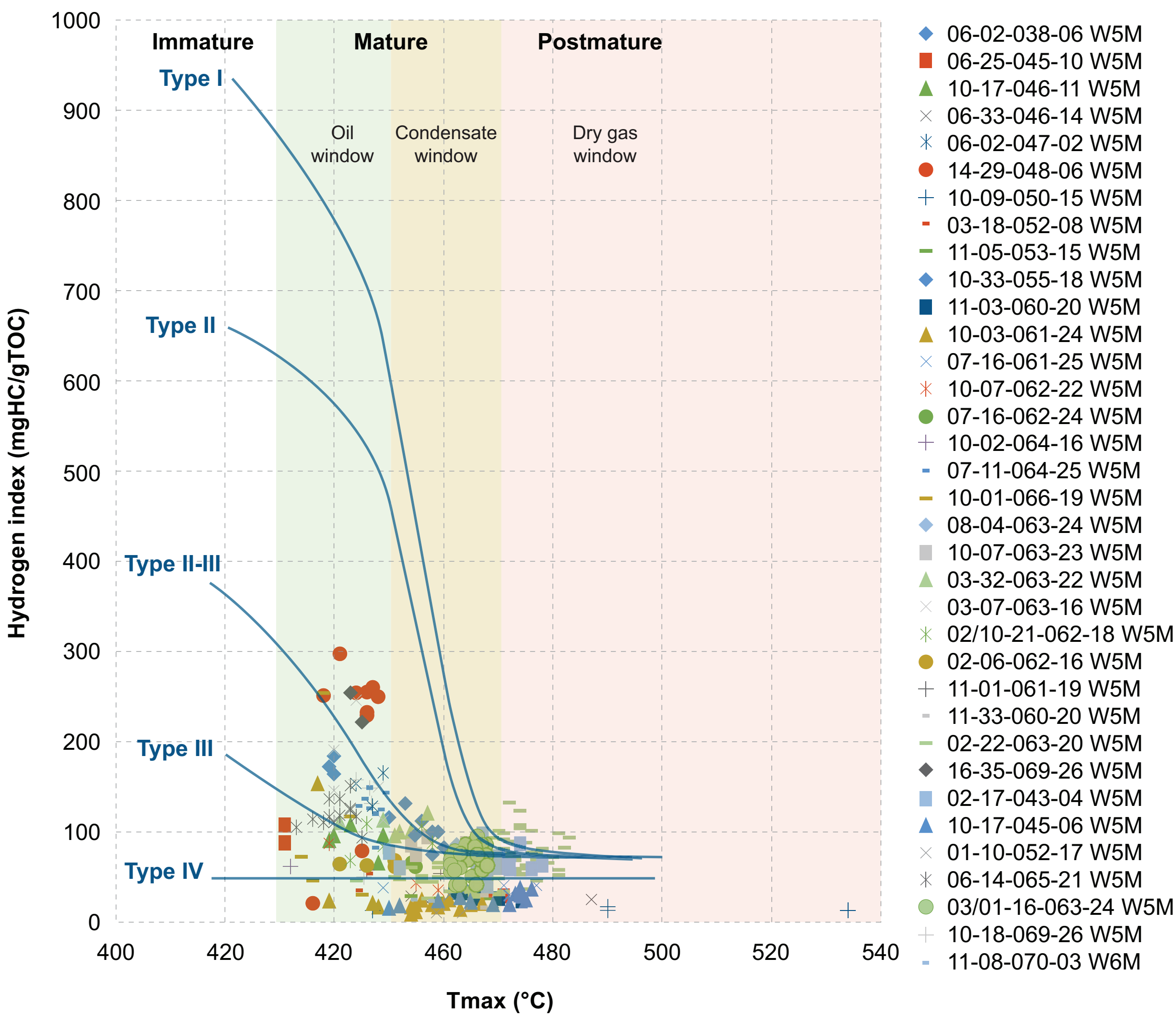


Figure 43. Measured T_{max} data for 35 wells within the Kaybob and Edson-Willesden Green assessment areas

Appendix 4 Deterministic & Analogue Well Lists

Gas Wells

Gas Wells UWI*	DLim† 5% EUR (MMcf)	DLim 10% EUR (MMcf)	DLim 15% EUR (MMcf)
100/05-05-056-18W5/00	1 470	1 303	1 165
100/04-22-056-18W5/02	1 209	1 063	943
100/13-33-057-18W5/00	9 118	8 070	7 191
100/04-03-058-18W5/00	3 398	2 996	2 659
100/01-31-059-18W5/00	3 874	3 421	3 044
100/01-25-059-19W5/02	3 953	3 419	2 987
100/16-33-059-19W5/00	3 935	3 456	3 064
102/16-18-060-17W5/00	2 345	2 020	1 758
102/03-05-060-18W5/00	1 997	1 751	1 546
100/16-10-060-18W5/00	1 805	1 583	1 398
100/13-11-060-18W5/00	1 163	1 039	934
100/01-24-060-18W5/00	1 338	1 180	1 050
100/11-25-060-18W5/00	1 663	1 437	1 256
100/12-26-060-18W5/00	2 190	1 927	1 709
100/16-02-060-19W5/00	2 104	1 854	1 646
100/13-03-060-19W5/00	4 732	4 165	3 693
102/13-09-060-19W5/00	1 457	1 270	1 117
102/16-10-060-19W5/00	2 589	2 274	2 013
100/09-31-060-19W5/00	3 027	2 643	2 330
100/08-36-060-19W5/00	2 608	2 294	2 032
100/05-11-060-20W5/02	2 587	2 261	1 997
100/03-13-060-20W5/00	3 883	3 383	2 984
102/16-21-060-20W5/00	6 191	5 459	4 847
100/13-36-060-20W5/00	5 040	4 415	3 906
103/13-33-061-18W5/00	2 044	1 802	1 600
100/01-32-061-20W5/00	3 584	3 197	2 875
100/01-24-061-22W5/00	2 576	2 282	2 037
102/01-36-061-22W5/00	1 560	1 381	1 232
100/08-04-062-17W5/02	1 049	927	826
100/16-05-062-17W5/00	1 796	1 580	1 401
100/05-08-062-18W5/00	975	838	726
100/12-27-062-18W5/00	954	841	746
100/11-26-062-19W5/00	2 546	2 210	1 932
102/02-08-062-20W5/00	2 826	2 493	2 216
102/02-34-062-20W5/02	5 298	4 654	4 127
100/16-04-062-21W5/00	1 571	1 383	1 227
100/01-16-062-21W5/00	1 260	1 125	1 013
103/16-19-062-21W5/00	5 998	5 277	4 672
100/14-21-062-21W5/00	2 859	2 506	2 218
102/01-16-062-22W5/00	3 534	3 084	2 707
100/06-10-062-23W5/02	2 611	2 293	2 032
1W0/05-04-062-24W5/00	3 961	3 549	3 206
100/01-25-062-25W5/02	2 598	2 322	2 092
100/05-19-063-18W5/02	2 195	1 911	1 675
100/07-19-063-18W5/00	1 480	1 298	1 148

100/01-21-063-18W5/00	403	361	326
102/03-21-063-18W5/00	526	468	419
100/07-06-063-19W5/00	2 526	2 237	1 997
100/08-06-063-19W5/00	3 008	2 647	2 349
102/03-19-063-19W5/00	1 689	100	1 340
100/05-20-063-19W5/00	1 561	1 367	1 210
100/12-30-063-19W5/02	1 544	1 352	1 196
100/06-11-063-20W5/00	1 460	1 299	1 165
100/03-22-063-21W5/00	4 965	4 368	3 871
100/15-26-063-21W5/00	3 209	2 794	2 451
103/13-23-063-24W5/00	577	510	454
102/16-19-064-18W5/00	1 202	1 048	920
100/04-03-064-21W5/02	654	584	526
100/04-11-064-22W5/00	1 448	1 269	1 122
102/05-30-064-22W5/02	423	375	335

* EURs provided reflect gas only and do not include estimates for condensate.

† Instantaneous limiting decline

Oil Wells

Oil Wells UWI	Solution Gas P10 (MMcf)	Solution Gas P50 (MMcf)	Solution Gas P90 (MMcf)	Oil P10 (Mbbl)	Oil P50 (Mbbl)	Oil P90 (Mbbl)
100/01-11-034-24W4/0	42	37	33	282	250	224
103/11-23-035-25W4/0	238	211	189	282	250	224
100/01-20-038-28W4/0	333	296	265	282	250	224
100/01-22-040-27W4/0	220	195	173	275	243	217
100/09-28-040-27W4/0	224	199	178	282	250	224
100/12-30-040-27W4/0	112	99	89	282	250	224
103/16-13-039-05W5/2	777	691	619	427	380	341
100/03-28-039-05W5/0	507	450	404	282	250	224
102/16-25-044-05W5/2	579	498	433	162	140	121
100/02-05-047-09W5/0	239	212	190	282	250	224
100/09-34-062-17W5/0	0	0	0	1	1	1
100/10-11-063-17W5/2	644	545	463	622	526	448
100/16-24-063-17W5/0	222	197	177	282	250	224
100/02-32-063-16W5/2	371	324	284	362	315	276
100/13-01-064-26W5/2	524	464	414	428	379	338
100/12-04-064-17W5/0	387	343	308	282	250	224
100/08-18-064-17W5/0	501	445	399	282	250	224
100/01-18-065-18W5/0	203	180	161	282	250	224
100/03-22-065-18W5/0	254	225	202	282	250	224
100/03-26-065-18W5/0	166	148	132	282	250	224
102/11-29-065-18W5/0	267	237	213	282	250	224
100/01-32-065-18W5/0	234	208	186	282	250	224
100/13-36-065-18W5/0	254	225	202	282	250	224
100/04-08-066-18W5/0	254	225	202	282	250	224

Appendix 5 Probabilistic Time-Series Methodology

1) Obtain cumulative gas production on a normalized monthly basis (730.5 hrs/month). Use linear interpolation to obtain possible data points.

2) Create correlations between each month's cumulative production (Q_n) and its proceeding month (Q_{n-1}). Each correlation should be linear in nature. Additionally, the correlation coefficient should approach one with each successive month. Determine the standard error for each correlation developed (Figure 45).

3) Determine the first month at which at least 33% of the population of wells are represented. Use the last month's cumulative production where at least 33% of the wells are represented to correlate to EUR (Table 10).

4) Create a correlation between the predetermined month and the deterministic EURs of the representative sample of wells (Figure 44).

5) Using the equation of the line from the month to month correlations as the equation, and the standard error as the standard distribution for a normal distribution, create a Monte Carlo simulation to calculate a given well's cumulative production value at the determined EUR correlation month from its last month of production.

6) Using the equation of the line and the standard error of the cumulative production to EUR correlation for the equation and standard distribution inputs for a normal distribution, respectively, create a Monte Carlo simulation to calculate the EUR of a well using the determined month's cumulative production value.

Table 10. Total well count by month

Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Count	178	175	172	167	155	148	145	134	126	118	113	109	101	94	89	80	77	72	65	56
Percent of Total (%)	97.3	95.6	94.0	91.3	84.7	80.9	79.2	73.2	68.9	64.5	61.8	59.7	55.2	51.4	48.6	43.7	42.1	39.3	35.5	30.6

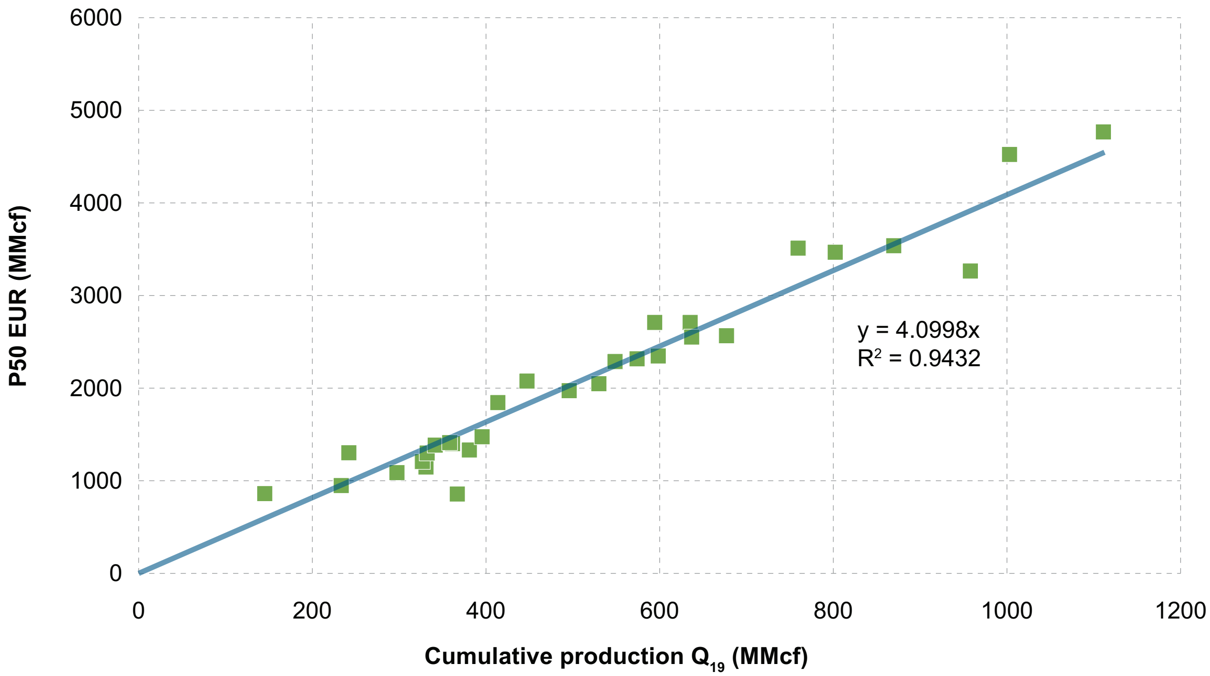


Figure 44. Final month-to-EUR correlation

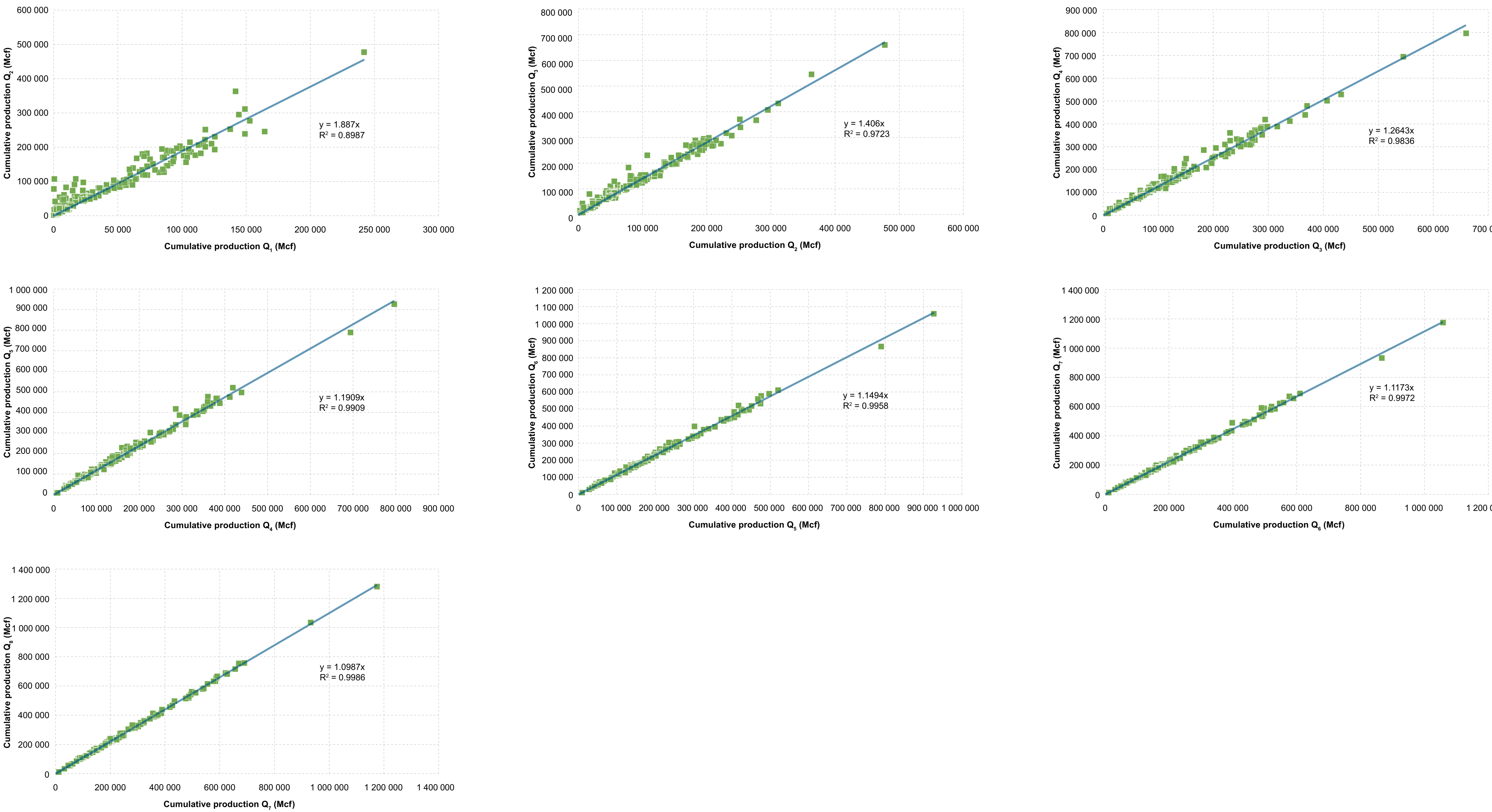


Figure 45. Monthly cumulative production correlations

Appendix 6 Probabilistic Well List

Gas Wells UWI	Gas P10 (MMcf)	Gas P50 (MMcf)	Gas P90 (MMcf)	Cond P10 (Mbbl)	Cond P50 (Mbbl)	Cond P90 (Mbbl)
100/12-19-040-07W5/0	1 558	1 398	1 213	26	24	21
100/09-24-040-08W5/3	1 558	1 398	1 213	26	24	21
100/02-25-040-08W5/0	1 558	1 398	1 213	26	24	21
102/10-03-041-05W5/3	703	618	547	12	11	9
100/16-15-041-05W5/0	1 493	1 314	1 162	25	22	20
102/04-33-041-05W5/0	1 040	924	828	18	16	14
100/02-35-041-07W5/2	1 513	1 343	1 203	177	157	141
100/06-27-041-08W5/0	1 506	1 346	1 213	101	90	81
100/03-06-042-05W5/2	656	578	513	44	39	34
100/11-33-042-06W5/0	1 746	1 549	1 386	204	181	162
100/01-09-042-07W5/0	2 565	2 268	2 022	300	265	237
100/16-05-042-08W5/2	1 722	1 546	1 400	76	68	62
100/13-17-043-04W5/2	851	745	659	14	13	11
100/10-19-043-04W5/0	1 338	1 201	1 042	90	80	70
100/09-36-043-05W5/2	1 338	1 201	1 042	90	80	70
100/03-06-043-07W5/2	3 593	3 159	2 803	61	54	48
100/01-06-044-05W5/2	1 990	1 752	1 554	233	205	182
100/13-12-044-06W5/0	2 390	2 091	1 845	160	140	124
100/07-16-044-07W5/2	1 670	1 484	1 333	28	25	23
100/08-09-044-08W5/2	1 348	1 207	1 090	23	21	19
100/09-24-044-10W5/2	1 338	1 201	1 042	23	20	18
100/01-07-045-05W5/2	2 658	2 337	2 070	45	40	35
100/02-16-045-06W5/0	1 955	1 723	1 529	33	29	26
103/11-15-045-07W5/0	718	631	559	12	11	10
102/06-20-046-03W5/0	1 877	1 687	1 461	32	29	25
100/05-27-046-03W5/0	1 877	1 687	1 461	32	29	25
100/10-13-046-04W5/0	2 049	1 802	1 596	35	31	27
100/15-08-046-09W5/2	1 606	1 409	1 245	188	165	146
100/12-23-052-16W5/2	2 647	2 974	2 647	45	51	45
100/05-05-056-18W5/0	1 714	1 538	1 334	29	26	23
100/04-22-056-18W5/2	1 338	1 201	1 042	23	20	18
100/13-33-057-18W5/0	9 664	8 890	7 525	164	151	128
100/07-14-057-22W5/3	4 084	3 985	3 181	69	68	54
100/04-03-058-18W5/0	3 681	3 361	2 866	63	57	49
100/01-31-059-18W5/0	4 152	3 725	3 233	71	63	55
102/16-03-059-19W5/0	1 514	1 351	1 180	26	23	20
103/03-19-059-19W5/0	5 666	5 110	4 412	96	87	75
102/06-19-059-19W5/0	5 040	4 545	3 924	86	77	67
102/09-19-059-19W5/0	4 561	4 109	3 551	78	70	60
100/01-25-059-19W5/2	3 417	3 066	2 661	58	52	45
100/16-33-059-19W5/0	3 914	3 511	3 048	67	60	52
100/01-24-059-20W5/2	6 214	5 481	4 838	106	93	82
100/13-36-059-20W5/0	5 040	4 545	3 924	86	77	67
100/14-36-059-20W5/0	4 050	3 654	3 153	69	62	54
100/15-36-059-20W5/0	5 040	4 545	3 924	86	77	67
102/16-36-059-20W5/0	5 011	4 271	3 901	85	73	66
102/16-18-060-17W5/0	2 013	1 806	1 567	34	31	27

Gas Wells UWI	Gas P10 (MMcf)	Gas P50 (MMcf)	Gas P90 (MMcf)	Cond P10 (Mbbl)	Cond P50 (Mbbl)	Cond P90 (Mbbl)
104/05-20-060-17W5/3	0	0	0	0	0	0
100/16-33-060-17W5/0	1 350	1 209	1 051	158	141	123
100/01-01-060-18W5/0	1 009	919	786	17	16	13
102/03-05-060-18W5/0	1 743	1 531	1 357	30	26	23
100/16-10-060-18W5/0	1 736	1 558	1 352	30	26	23
100/13-11-060-18W5/0	1 434	1 286	1 116	24	22	19
100/16-13-060-18W5/0	1 667	1 500	1 298	28	26	22
100/01-24-060-18W5/0	1 513	1 358	1 178	26	23	20
100/11-25-060-18W5/0	1 780	1 597	1 386	30	27	24
100/12-26-060-18W5/0	2 269	2 036	1 767	39	35	30
100/13-26-060-18W5/0	1 725	1 548	1 344	29	26	23
100/16-02-060-19W5/0	2 039	1 830	1 588	35	31	27
100/13-03-060-19W5/0	4 608	4 142	3 588	78	70	61
102/13-09-060-19W5/0	1 089	977	848	19	17	14
102/16-10-060-19W5/0	2 843	2 516	2 214	151	133	117
102/14-25-060-19W5/0	1 877	1 687	1 461	32	29	25
100/09-31-060-19W5/0	2 858	2 565	2 226	49	44	38
100/08-36-060-19W5/0	2 593	2 333	2 019	44	40	34
100/05-11-060-20W5/2	2 583	2 318	2 012	44	39	34
100/03-13-060-20W5/0	3 610	3 239	2 811	242	217	188
102/16-21-060-20W5/0	6 020	5 401	4 687	102	92	80
100/04-31-060-20W5/0	5 037	4 412	3 920	86	75	67
100/16-33-060-20W5/2	5 147	4 630	4 008	88	79	68
100/13-36-060-20W5/0	4 514	4 050	3 515	77	69	60
100/03-07-061-17W5/0	744	658	577	87	77	67
100/02-02-061-18W5/0	1	1	1	0	0	0
100/01-20-061-18W5/0	1 660	1 489	1 292	360	323	280
100/01-22-061-18W5/0	1 795	1 613	1 397	390	350	303
103/13-33-061-18W5/0	1 862	1 671	1 450	311	279	242
102/14-08-061-20W5/0	5 931	5 239	4 618	101	89	79
100/16-10-061-20W5/0	5 091	4 430	3 963	87	75	67
100/14-21-061-20W5/0	4 149	3 383	3 230	71	58	55
100/01-32-061-20W5/0	4 310	3 867	3 356	73	66	57
100/01-24-061-22W5/0	2 754	2 496	2 145	47	42	36
100/01-36-061-22W5/2	918	821	715	16	14	12
102/01-36-061-22W5/0	1 611	1 446	1 255	27	25	21
100/09-31-061-24W5/0	5 626	5 051	4 381	658	591	513
100/07-07-062-16W5/0	1 343	1 137	1 047	359	304	280
100/03-08-062-16W5/2	1 232	1 095	960	390	347	304
100/08-04-062-17W5/2	1 050	942	817	175	157	137
100/16-05-062-17W5/0	1 749	1 569	1 362	379	340	295
100/13-14-062-17W5/0	1 421	1 267	1 104	308	275	240
100/16-17-062-17W5/0	1 040	924	812	226	201	176
100/01-27-062-17W5/0	850	764	661	227	204	176
102/05-31-062-17W5/0	850	774	662	312	284	243
103/05-31-062-17W5/0	754	690	587	164	150	127
100/05-08-062-18W5/0	654	586	509	109	98	85
103/07-22-062-18W5/2	1 558	1 398	1 213	338	303	263
100/11-27-062-18W5/0	942	840	733	157	140	122

Gas Wells UWI	Gas P10 (MMcf)	Gas P50 (MMcf)	Gas P90 (MMcf)	Cond P10 (Mbbl)	Cond P50 (Mbbl)	Cond P90 (Mbbl)
100/12-27-062-18W5/0	958	858	746	208	186	162
100/01-31-062-18W5/0	1 315	1 158	1 024	220	193	171
100/07-34-062-18W5/0	966	877	752	161	146	126
100/08-34-062-18W5/2	756	676	589	202	181	157
102/04-08-062-19W5/0	1 883	1 742	1 466	126	117	98
100/11-26-062-19W5/0	2 190	1 965	1 705	147	132	114
102/02-08-062-20W5/0	2 866	2 572	2 232	49	44	38
1S0/02-16-062-20W5/2	1 693	1 519	1 318	29	26	22
100/01-26-062-20W5/0	3 722	3 603	2 898	249	241	194
100/03-26-062-20W5/0	6 505	6 018	5 064	436	403	339
102/03-26-062-20W5/0	4 274	4 076	3 328	286	273	223
102/04-26-062-20W5/0	6 864	6 395	5 343	460	428	358
100/02-28-062-20W5/0	4 028	3 619	3 136	270	242	210
102/02-34-062-20W5/2	5 001	4 486	3 894	335	301	261
100/08-34-062-20W5/0	3 916	3 428	3 049	262	230	204
100/16-04-062-21W5/0	1 671	1 485	1 301	28	25	22
100/01-16-062-21W5/0	1 489	1 336	1 159	25	23	20
100/14-16-062-21W5/0	20	20	20	2	2	2
103/16-19-062-21W5/0	5 238	4 695	4 078	89	80	69
100/14-21-062-21W5/0	3 047	2 733	2 372	52	46	40
102/13-22-062-21W5/0	2 385	2 140	1 857	41	36	32
100/02-29-062-21W5/0	5 286	4 696	4 115	90	80	70
102/09-29-062-21W5/0	3 905	3 698	3 040	66	63	52
100/16-29-062-21W5/0	4 480	4 110	3 488	76	70	59
102/01-32-062-21W5/0	3 183	3 006	2 479	54	51	42
102/08-32-062-21W5/0	2 809	2 663	2 187	48	45	37
100/09-32-062-21W5/0	2 210	2 068	1 721	38	35	29
102/01-16-062-22W5/0	2 679	2 429	2 087	46	41	35
100/02-25-062-22W5/0	2 074	1 909	1 615	243	223	189
100/06-10-062-23W5/2	2 692	2 416	2 097	46	41	36
100/15-15-062-23W5/2	3 211	2 886	2 500	215	193	168
100/12-28-062-23W5/0	3 155	2 845	2 457	369	333	287
1W0/05-04-062-24W5/0	5 112	4 587	3 981	598	537	466
100/16-05-062-24W5/0	2 027	1 856	1 578	237	217	185
102/16-11-062-25W5/0	7 987	7 111	6 220	1 334	1 188	1 039
100/01-25-062-25W5/2	3 446	3 092	2 684	576	516	448
100/03-03-063-16W5/0	362	331	282	151	138	118
100/05-19-063-18W5/2	1 604	1 439	1 249	188	168	146
100/06-19-063-18W5/0	1 279	1 148	996	150	134	117
102/06-19-063-18W5/0	1 593	1 430	1 241	186	167	145
100/07-19-063-18W5/0	1 321	1 185	1 028	221	198	172
100/01-21-063-18W5/0	511	459	398	188	168	146
102/02-21-063-18W5/0	404	362	314	128	115	100
102/02-21-063-18W5/0	505	451	393	160	143	125
100/03-21-063-18W5/0	388	352	301	123	111	96
102/03-21-063-18W5/0	532	498	414	169	158	131
100/07-06-063-19W5/0	2 469	2 215	1 923	289	259	225
100/08-06-063-19W5/0	2 675	2 400	2 083	313	281	244
100/11-06-063-19W5/0	3 045	2 732	2 371	204	183	159

Gas Wells UWI	Gas P10 (MMcf)	Gas P50 (MMcf)	Gas P90 (MMcf)	Cond P10 (Mbbl)	Cond P50 (Mbbl)	Cond P90 (Mbbl)
100/03-11-063-19W5/0	1 554	1 394	1 210	182	163	142
102/04-11-063-19W5/0	1 686	1 513	1 313	197	177	154
102/03-19-063-19W5/0	1 912	1 715	1 489	319	286	249
100/04-19-063-19W5/2	2 041	1 832	1 590	239	214	186
1W0/05-19-063-19W5/0	1 332	1 195	1 037	222	200	173
100/05-20-063-19W5/0	1 627	1 460	1 267	353	317	275
100/12-30-063-19W5/2	1 537	1 379	1 197	257	230	200
100/15-09-063-20W5/0	1 187	1 065	924	258	231	201
100/05-11-063-20W5/0	1 999	1 793	1 556	234	210	182
100/06-11-063-20W5/0	1 651	1 481	1 286	193	173	150
102/07-11-063-20W5/0	2 194	1 968	1 708	257	230	200
100/10-11-063-20W5/0	1 032	926	804	172	155	134
100/02-22-063-20W5/2	1 233	1 107	960	268	240	208
100/06-24-063-20W5/0	2 288	2 041	1 782	268	239	208
100/07-24-063-20W5/0	788	691	614	132	115	102
100/08-24-063-20W5/0	1 508	1 337	1 174	252	223	196
100/08-36-063-20W5/0	1 519	1 363	1 183	330	296	257
102/08-02-063-21W5/0	4 519	4 175	3 519	77	71	60
102/09-02-063-21W5/0	3 969	3 630	3 090	67	62	53
103/16-06-063-21W5/0	2 524	1 385	1 967	169	93	132
103/04-08-063-21W5/0	3	3	3	1	1	1
103/06-08-063-21W5/0	3 437	3 193	2 677	230	214	179
100/10-08-063-21W5/0	4 277	3 707	3 330	73	63	57
100/01-11-063-21W5/0	4 292	3 926	3 342	73	67	57
100/04-12-063-21W5/0	2 945	2 629	2 293	50	45	39
100/13-15-063-21W5/2	3 675	3 339	2 861	246	224	192
100/09-16-063-21W5/0	2 872	2 599	2 236	49	44	38
103/09-16-063-21W5/0	3 018	2 755	2 350	51	47	40
100/03-22-063-21W5/0	4 609	4 135	3 589	309	277	240
100/15-26-063-21W5/0	2 408	2 169	1 875	523	471	407
100/15-01-063-22W5/0	1 603	1 464	1 248	188	171	146
100/08-23-063-22W5/2	4 040	3 670	3 145	473	429	368
102/08-23-063-22W5/0	2 805	2 469	2 185	328	289	256
102/12-24-063-22W5/0	2 610	2 342	2 033	436	391	340
100/14-24-063-22W5/0	3 024	2 578	2 355	505	431	393
100/08-33-063-22W5/0	2 386	2 143	1 858	398	358	310
100/12-34-063-22W5/0	3 584	3 046	2 790	778	661	606
100/14-34-063-22W5/0	2 736	2 482	2 131	594	539	462
100/15-34-063-22W5/0	2 551	2 164	1 986	554	469	431
100/06-09-063-23W5/2	2 462	2 228	1 917	411	372	320
100/13-32-063-23W5/0	1 978	1 783	1 541	429	387	334
100/15-34-063-23W5/0	1 925	1 739	1 499	321	290	250
100/12-02-063-24W5/0	2 309	2 063	1 799	386	344	300
103/13-23-063-24W5/0	724	651	564	121	109	94
100/16-36-063-25W5/2	1 004	998	782	419	416	326
103/04-07-064-18W5/0	1 230	1 112	957	267	241	208
102/16-19-064-18W5/0	1 009	912	786	269	243	210
100/04-29-064-19W5/0	872	762	679	276	242	215
100/01-07-064-20W5/2	2 364	2 120	1 840	513	460	399

Gas Wells UWI	Gas P10 (MMcf)	Gas P50 (MMcf)	Gas P90 (MMcf)	Cond P10 (Mbbl)	Cond P50 (Mbbl)	Cond P90 (Mbbl)
100/04-16-064-20W5/0	1 052	944	819	228	205	178
100/04-25-064-20W5/0	1 461	1 311	1 138	463	416	361
100/04-29-064-20W5/2	869	780	677	189	169	147
100/08-29-064-20W5/0	1 057	948	823	335	301	261
100/04-03-064-21W5/2	873	784	680	146	131	114
100/04-15-064-21W5/0	1 467	1 318	1 143	318	286	248
102/07-17-064-21W5/0	854	793	665	185	172	144
100/10-17-064-21W5/2	894	833	697	194	181	151
100/06-06-064-22W5/2	1 967	1 771	1 532	427	384	332
100/04-11-064-22W5/0	1 495	1 341	1 164	324	291	253
102/05-30-064-22W5/2	590	525	460	158	140	123
102/01-03-064-23W5/0	1 201	1 162	935	201	194	156
103/01-03-064-23W5/0	1 000	884	777	167	148	130
104/01-03-064-23W5/0	1 823	1 723	1 420	304	288	237
100/04-12-064-23W5/0	2 524	2 264	1 966	422	378	328
103/01-07-065-19W5/0	472	401	367	197	167	153
100/06-11-065-22W5/0	704	625	546	294	261	228
102/07-11-065-22W5/0	818	734	638	341	306	266